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CORP COMMISSION
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Transcript Exhibit(s)

Docket #(s): E01933A-12-0291

Exhibit # : Opower1, Opower2, RUCO1-RUCO3
RUCO6-RUCO10, SEIA1, SAHBA1,
SAHBA2, SAHBA3, SAWUA1-SAWUA3
SWEEP1, SWEEP2, SWEEP3

Part 2 of 9

Arizona Corporation Commission
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OPOWER-1

EXHIBIT

Opower-1

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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE – Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING DIRECT TESTIMONY OF JIM KAPSIS ON BEHALF OF OPOWER, INC.**

Opower, Inc. ("Opower") by and through its undersigned counsel, hereby provides notice that it has this day filed the written direct testimony of Jim Kapsis.

RESPECTFULLY SUBMITTED this 21st day of December, 2012.

MUNGER CHADWICK, P.L.C.

By [signature]
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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE – Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING DIRECT TESTIMONY OF JIM KAPSIS ON BEHALF OF OPOWER, INC.**

Direct Testimony of

Jim Kapsis

Opower, Inc.

Introduction

Q. Please state your name and business address.

A. My name is Jim Kapsis. My business address is 1515 N. Courthouse Rd. Arlington, VA 22201.

Q. For whom are you testifying?

A. I am testifying on behalf of Opower, Inc. (Opower).

Q. Please describe Opower.

A. Opower is an Arlington, VA-based company that provides information-based behavioral energy efficiency programs for over 75 utilities in 30 states, including Tucson Electric Power, UNS Electric, and Arizona Public Service in Arizona. This year, Opower will deliver personalized energy usage insights to more than 15 million residential customers through paper mail, email, websites, smart phones, and text messages.

Opower's Home Energy Reports program consistently motivates customers to save an average of 1.5-3% on their energy bills. Opower has helped its utility partners drive this level of energy efficiency at scale, achieving more than 1.6 terawatt-hours in energy savings, and driving significant increases in customer energy efficiency program participation and overall customer satisfaction.

Q. What are your professional qualifications?

A. I am the Senior Director of Market Development and Strategy at OPOWER. My team and I are responsible for Opower's market development, policy, and regulatory work in North America. Prior to Opower, I was an Energy Advisor at the U.S. Department of the Treasury. I have also held positions at the U.S. State Department, Defense Department, and in the U.S. Congress. I have a B.A. in political science from Haverford College and a M.P.A. from Princeton University. I have testified in numerous regulatory and legislative proceedings on efficiency policy and regulation.

Q. What is the purpose of your testimony?

A. In my testimony, I will:

- Summarize the public interest in increasing electric energy efficiency, and explain why public policy action is necessary to remove regulatory barriers to energy efficiency markets;

- Describe how current regulatory uncertainty in some areas of Arizona is paralyzing the business environment for energy efficiency, preventing companies like Opower from doing business, and depriving ratepayers of energy savings benefits and;
- Explain why Tucson Electric Power's ("TEP") Energy Efficiency Resource Plan would create a more stable and predictable business environment for companies like Opower and would ensure that benefits to the ratepayers always exceed costs.

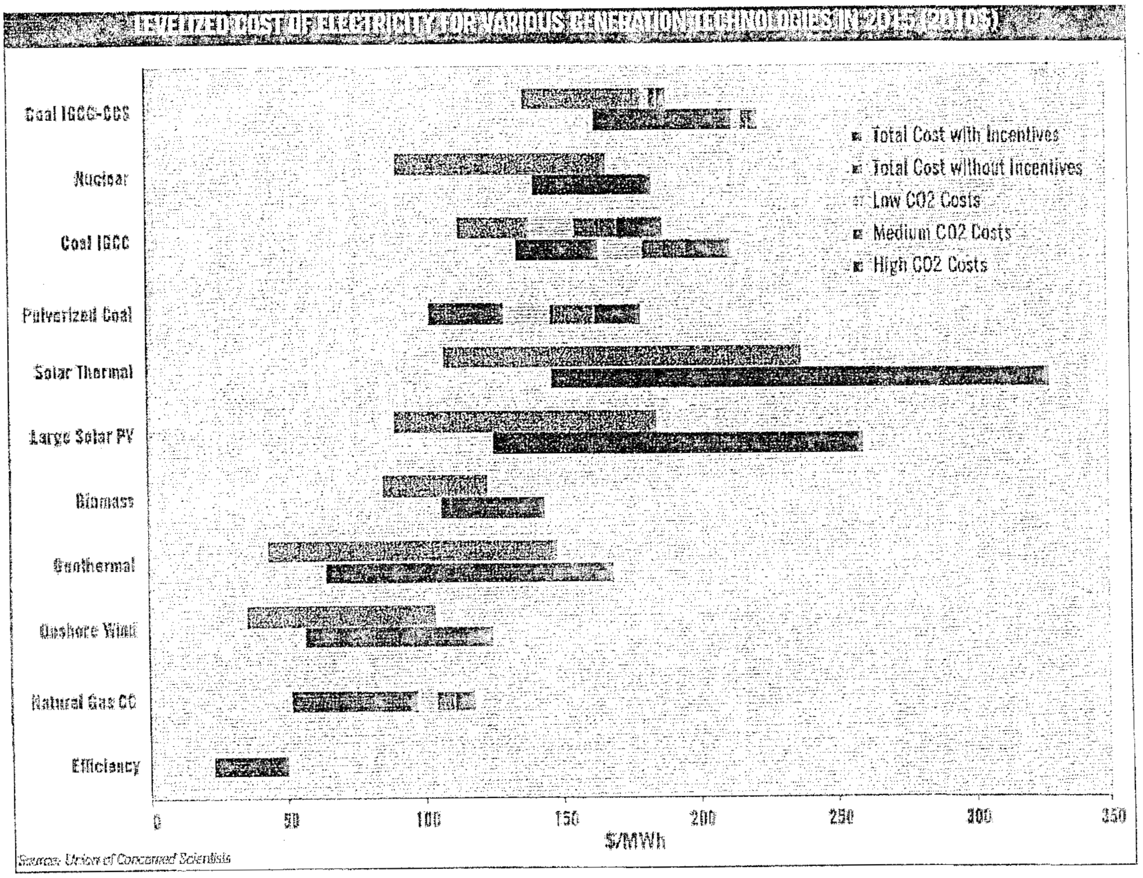
The Public Interest in Increasing Electric Energy Efficiency

Q. What is the public interest in increasing electric efficiency?

A. Electric energy efficiency delivers significant and cost-effective benefits for TEP customers, the electric system, and the economy. Cost-effective energy efficiency is a reliable resource, which is less expensive than other energy sources. In its June 15th testimony in Docket No. E-01933A-11-0055, TEP noted that through its Integrated Resource Planning efforts, the Company has shown "that certain DSM/EE measures can be the lowest cost generation resource available." Figure 1 below shows the levelized cost of electricity, or the cost per megawatt-hour for electricity over the life of the plant, for a variety of energy resources, including energy efficiency and renewable sources.

Because cost-effective energy efficiency is the lowest cost generation resource, increasing investment in energy efficiency efforts can save consumers money through lower electric bills. Investment in additional energy efficiency programs is in the public interest as it allows for the diversification of the energy resource portfolio of utilities, enhances grid reliability, and defers investment in unnecessary and expensive infrastructure. Finally, by reducing electricity demand, energy efficiency mitigates the need to increase electricity and fuel prices and reduces customer vulnerability and exposure to price volatility. Put simply, energy efficiency saves ratepayers money.

Figure 10



Source: Freese, Barbara, et.al, 2011. "A Risky Proposition." Union of Concerned Scientists.

Q. How do behavioral energy efficiency programs deliver energy and bill savings to households?

A. Behavior-based programs provide customers with information that compares a customer's household energy use to that of similar households via mail-based reports and other communications channels. Armed with such information customers are then motivated to modify their behavior and undertake actions and/or make energy efficient product purchases that result in energy savings. Behavior-based programs through Opower are saving 25,000 TEP customers and 80,000 APS customers roughly $30-40/year on their bills, or the equivalent of $3.2-4.2 million a year.

These programs make an important contribution to any energy efficiency portfolio by helping to maximize the potential savings of installed efficiency programs, driving up participation in other utility-run efficiency programs, and delivering savings to all residential ratepayers – including hard-to-reach households, such as low income, renters, and seniors. In recent years, behavioral programs have become critical components of energy efficiency portfolios throughout the country. The widespread acceptance of behavioral programs is a reflection of the fact that these programs fill an important need for customer energy-savings information, have been rigorously evaluated, and offer significant energy savings.

Q. How do behavioral energy efficiency programs work?

A. Behavioral programs like the Home Energy Reports program use randomized control trials (RCTs) – a form of experimental design – to measure to isolate and cleanly measure energy savings impacts at the 95% confidence interval or greater. RCTs are considered the gold standard in statistical evaluation and are used, for example, by the U.S. Food and Drug Administration in determining whether or not to approve new pharmaceuticals for human consumption. This methodology is consistent with the recommendations of the U.S. Department of Energy-led State & Local Energy Efficiency (SEE) Action Network's EM&V of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations."[1] SEE Action is a consensus group comprised of utilities, consumer advocates, commission staff, and government officials. This methodology is also consistent with the National Action Plan for Energy Efficiency guidelines[2], the California Evaluators Manual[3], and The Brattle Group's Principles of Behavior-Based Energy Efficiency.[4]

Q. Why is public policy action necessary to align utility incentives with investment in energy efficiency?

A. Currently, utilities can receive a rate of return on capital assets like power plants, but not on lower-cost resources like energy efficiency. This incentivizes utilities to build more plants, increasing the rate base and raising costs for consumers in the long-term. Many states throughout the US, including Arizona, have recognized the importance of energy efficiency as a resource, and have created Energy Efficiency Resource Standards or

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[1] "Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations," May 2012, State & Local Energy Efficiency Action Network, available here: http://www1.eere.energy.gov/seeaction/pdfs/emv_behaviorbased_eeprograms.pdf

[2] National Action Plan for Energy Efficiency. *Model Energy Efficiency Program Impact Evaluation Guide.* November 2007. Available online at: < http://www1.eere.energy.gov/office_eere/pdfs/napee_evaluation_guide.pdf>

[3] California Public Utilities Commission. *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals.* April 2006. Available Online at: <http://www.calmac.org/events/EvaluatorsProtocols_Final_AdoptedviaRuling_06-19-2006.pdf>

[4] Sergici, Sanem and Ahmad Faruqui. *Measurement and Verification Principles for Behavior-Based Efficiency Programs.* May 2011. Available online at: http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf

EERS', to require utility investment in energy efficiency. These policies have successfully created a market for energy efficiency in over 26 states. Although these policies are helpful in driving energy efficiency investment, without a guaranteed program cost recovery mechanism, utilities would not have the incentive to invest in energy efficiency as they would if such cost recovery was guaranteed.

Regulatory Uncertainty for TEP Paralyzes the Business Environment for Energy Efficiency; Depriving Customers of Bill Savings Benefits

Q. Why did Tucson Electric Power choose to run a behavioral energy efficiency program?

A. In Decision No. 71787 (July 2010), the Arizona Corporation Commission ("Commission") ordered TEP to "develop a bill comparison pilot program that will allow its customers to compare their energy usage with that of other similarly situated customers, and submit the pilot program proposal, no later than September 1, 2010, for Staff review and Commission consideration."

In response, TEP submitted a proposed pilot program in August 2010, noting its plans to deliver the program to 25,000 customers in the first year, with expansion to 40,000 in the second year. In Decision No. 72254 (April 2011), the Commission approved the pilot program through December 2012. In October 2011, 25,000 households in TEP's service territory began receiving Home Energy Reports.

Q. Why were existing programs suspended or cut in 2012?

A. Although the Commission approved new EE programs, like the Home Energy Report program, and expanded budgets throughout the 2010-2011 timeframe, the adjustor mechanism to collect the Commission-approved EE program funds has not been reset since June 1, 2010.

In January 2011, TEP filed a 2011-2012 EE Implementation Plan ("EE Plan") with the Commission. The EE Plan provided for the continuation and expansion of existing customer energy saving programs, including the Home Energy Reports program as well as the launch of new such programs. TEP's proposal also included a request for expedited review and approval by the Commission with the goal of launching new and expanding existing customer opportunities by June 2011. This expedited review and Commission approval did not occur, and the plan was not considered until January 2012, after the 2011 program year had concluded.

The Commission then urged stakeholders to negotiate a compromise position, the

"Modified Plan," which included a proposal to reset the adjustor mechanism. After evidentiary hearings were conducted for the Modified Plan, the Commission did not approve the Modified Plan at the March 2012 Open Meeting, and as a result, the decision to fund such programs was delayed further. In response, TEP submitted an Updated Modified Plan in May 2012. Because no action has been taken to approve the Modified Plan, or the Updated Modified Plan, the adjustor mechanism has not been reset to adequately fund Commission-authorized programs and program budgets. As a result, beginning in March 2012, many of TEP's existing programs were suspended or downsized and expansions were delayed. The Home Energy Reports program was suspended as of October 2012.

Q. What impacts will this have on TEP's statutory obligations?

A. Without adequate cost recovery, TEP will be unable to meet its obligations in the Commission's Electric Energy Efficiency rules (A.A.C. R14-2-2401 et seq.) ("EE Rules").

Q. What impacts will this have for energy efficiency businesses in the state?

A. Energy efficiency businesses like Opower need long-term regulatory certainty, similar to what they enjoy in other states, to thrive in Arizona. Regulatory certainty for utilities like TEP translates directly to market certainty for businesses that serve utilities in achieving their regulatory objectives. Unclear expectations create market uncertainty. This can occur when energy efficiency programs are approved but unfunded or when utilities are given aggressive energy efficiency goals but denied the resources to meet those goals. Such market uncertainty forces companies to look to other states to do business.

Q. What impacts will this have for Tucson Electric Power's ratepayers?

A. The TEP Home Energy Reports program for 25,000 households was projected to saved bill payers more than 18 GWh – translating to an estimated $1.8 million or roughly $70 saved per household – in 2012 and 2013. When TEP's bridge plan was not approved, the existing program was put on hold, denying these households the information they need to continue to save over the remaining 15 months of the program.

<u>Opower's Position on TEP's Energy Efficiency Resource Plan</u>

Q. What public policy models successfully incentivize investment in lower cost energy efficiency resources?

A. There are a variety of public policy models that incentivize energy efficiency, but the most successful states combine a strong mandate with guaranteed program and lost revenue recovery in addition to net economic benefit opportunities.

One Southwestern example is Colorado, which provides cost recovery and lost revenue recovery (through a disincentive offset) for all Black Hills Energy and Public Service Company of Colorado (PSCo) and programs. In addition, the Colorado Public Utilities Commission provided PSCo the ability to earn a percentage of net economic benefits resulting from energy efficiency programs (in addition to program cost recovery and lost revenue compensation). As a result of this decision, PSCo is now eligible to earn a percentage of net economic benefits resulting from the companies demand side management portfolio, based upon achievement of annual EERS savings goals.

Q. Why should TEP receive program cost recovery for their investments in energy efficiency?

A. Cost recovery is the most basic requirement for utilities to conduct energy efficiency programs – without a guarantee of basic recovery for the administrative costs of running a program, the utility does not have the regulatory certainty to invest in any resources. Given its recent difficulty in receiving timely cost recovery, TEP proposed an innovative solution – creation of an energy efficiency regulatory asset with a three-year planning horizon, establishing DSMS rates for 2014, 2015, and 2016, and setting cost recovery in place for that time period. This longer planning horizon would help create regulatory certainty for TEP, which would create a more stable and predictable business environment for efficiency companies and contractors. This would then translate into appreciable benefits for ratepayers, who need clear market signals and information about their energy use in order to take advantage of energy efficiency programs. Additionally, the longer time horizon would reduce the burden on Staff and Commission resources for regular review, but would maintain an oversight mechanism through yearly progress reporting.

Q. Why should TEP receive carrying costs and a return for their investments in energy efficiency?

A. The EE Rules require utilities to reduce their energy sales, and compliance with those rules results in reductions in the volume of sales to customers. This produces reductions in TEP's ability to recover its fixed costs with each additional kWh saved, and further, reduces TEP's ability to earn a return on its investment. To alleviate this pressure, TEP proposed to receive a return on investments based on their approved Weighted Average Cost of Capital, with an additional 200 basis points for ROE. Currently, TEP is incentivized to invest in higher-cost generation assets, because the Company can receive a rate of return on those capital assets. In order to treat energy efficiency similarly to traditional supply-side resources, TEP and its shareholders need a rate of return to compensate for the opportunity cost of not investing in other assets. Further, there is higher risk to the company associated with more "intangible" assets like energy efficiency, and an enhanced ROE is warranted for the increased risk associated with those investments.

Q. Is there a precedent for a Utility Commission to capitalize energy efficiency expenses over time?

A. There are past examples of amortization of energy efficiency expenses over time, with additional basis points for inclusion of energy efficiency in a portfolio, some of which are detailed below:[5]

- In 2011, the Bureau of Public Utilities in New Jersey approved a revenue requirement for PSE&G that included calculation of a return on investment for electric and gas energy efficiency programs with amortization over 60 months.[6]
- In Wisconsin, Wisconsin Power & Light (Alliant Energy) may earn the same rate-of-return on its investments in energy efficiency made through its "Shared Savings" program for Commercial/Industrial (C/I) customers as it earns on other capital investments, like power plant construction.[7]
- Up to 2009, the PUC Nevada regularly approved return on equity (RoE) "adders" of 500 basis points on the equity portion of utility rates.
- A 1988 order from the Massachusetts PSC declared that: "Electric companies can earn a return on C&LM [conservation and load management] equipment and materials, along with related capitalized labor and administrative costs, where such expenditures will provide long-run benefits to ratepayer."[8]
- In 1979 and 1980, the Idaho PUC authorized Pacific Power & Light (PPL) to ratebase loans to residential customers for weatherizing their homes, as well as the cost of water heater wraps given to customers. [9]
- In Washington State, Puget Sound Power and Light was allowed to ratebase most of its DSM budget, including conservation-related advertising, informational, and educational expenditures. [10]

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[5] Regulatory Incentives for Demand-Side Management, ACEEE, 1992

[6] State of New Jersey, Board of Public Utilities. Stipulation of Settlement. 2011. BPUA Docket No. E011010030. June 30.

[7] Wisconsin PSC. Docket 6680-UR-114, October 8, 2008 order

[8] Massachusetts Department of Public Utilities. 1988. Order. 89-36-F. November 30.

[9] Idaho Public Utilities Commission. 1980. Order NO. 15891. September 26., AND Idaho Public Utilities Commission. 1979. Order 14466. March 9.

[10] Washington. 1980. Rev. Code Wash. 80.28.025.

Q. Does Opower recommend a similar Energy Efficiency Resource Plan model for all utilities in Arizona?

A. No. The model for incentivizing energy efficiency through cost recovery, lost revenue recovery, and rate of return can vary from utility to utility based on their unique circumstances. For example, the EE Rules treat each utility separately for the purpose of performance incentives, stating "*an affected utility* may propose for Commission review a performance incentive to assist in achieving the energy efficiency standard set forth in the R14-2-2404."

Conclusion

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP – Chairman
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

EXHIBIT
Opower-2
ADMITTED

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING OF OPOWER, INC.**

Opower, Inc. hereby provides notice of filing of the prepared Direct Testimony of Diana Genasci in support of the Settlement Agreement in the above-docketed proceeding.

Respectfully submitted this 15th day of February, 2013.

MUNGER CHADWICK, P.L.C.

By

Robert J. Metli
Attorneys for Intervenor Opower, Inc.

Arizona Corporation Commission
DOCKETED
FEB 15 2013
DOCKETED BY

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COPY of the foregoing served by email or mail this 15th day of February 2013 to:

All Parties of Record

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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP – Chairman
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291

Prepared Direct Testimony Of Diana Genasci For Opower, Inc.

Prepared Direct Testimony
of
Diana Genasci
In Support of the Settlement Agreement
for
Opower, Inc.

Q: Please state your name and business address.

A: My name is Diana Genasci. My business address is 642 Harrison Street, Second floor, San Francisco, CA 94107.

Q: For whom are you testifying?

A: I am testifying on behalf of Opower, Inc. ("Opower").

Q: Have your previously filed Direct Testimony in this proceeding?

A: No.

Q: Has Opower submitted Direct Testimony in this case?

A: Yes. Opower submitted direct testimony of Mr. Jim Kapsis. Mr. Kapsis:

- Summarized the public interest in increasing electric energy efficiency, and explained why public policy action is necessary to remove regulatory barriers to energy efficiency markets;
- Described how current regulatory uncertainty in some areas of Arizona is paralyzing the business environment for energy efficiency, preventing companies like Opower from doing business, and depriving ratepayers of energy savings benefits and;
- Explained why Tucson Electric Power's ("TEP") Energy Efficiency Resource Plan would create a more stable and predictable business environment for companies like Opower and would ensure that benefits to the ratepayers always exceed costs.

Q: Will you be adopting Mr. Kapsis' Direct Testimony in this case at the hearing?

A: Yes, I will.

Q: What are your professional qualifications?

A: I am the manager of Market Development and Regulatory Affairs–West for Opower. I am responsible for managing Opower's regulatory and policy strategy to promote energy efficiency throughout California and the Southwestern United States. Prior to Opower, I was an administrative attorney at the Public Utilities Commission of Nevada. I have also held positions at the California Public Utilities Commission ("CPUC") and was an associate attorney for an energy law firm, where I represented clients in energy and regulatory matters in the electric and gas industries with a focus on matters before the CPUC. I have a B.A. in Economics from California State University, Sacramento and a Juris Doctor from the University of California, Hastings College of the Law.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to support section 7 of the TEP Settlement Agreement filed with the Arizona Corporation Commission ("Commission") on February 4, 2013. I will explain why the public interest is served by supporting TEP's efforts to reinstate on March 1, 2013, TEP's EE programs that were suspended or cut by allowing TEP to recover those costs through the Energy Efficiency Resource Plan as proposed in Staff's direct testimony in Docket No. E-01933A-11-0055 ("EE Plan").

Q: **Is Opower a signatory to the Settlement Agreement?**

A: Yes.

Q: What is the public interest in supporting TEP's reinstatement of EE Programs that were suspended or cut due to lack of funding?

A: TEP's commitment to reinstate and receive cost recovery for EE programs that were suspended or cut serves the public interest in two ways. First, EE programs will be able to deliver significant savings for a large number of TEP residential customers during the upcoming summer months and help TEP to shift energy use from peak times during the upcoming summer months. Second, energy efficiency companies will be given more long-term regulatory certainty to continue to do business in the state of Arizona. TEP's suspension of existing EE programs prevents EE businesses like Opower from providing energy savings to customers and paralyzes the business environment for energy efficiency in the state. If TEP is unable to recover its costs to meet its existing and future EE obligations, EE businesses will likely view any future investments in the state as too much of a risk.

Q: Explain why TEP should reinstate EE programs that have been suspended or cut in advance of the summer season.

A: TEP offers a variety of energy efficiency and conservation programs for business and residential customers. EE programs help TEP customers to save energy and money, while reducing peak demand. In Arizona, electricity demand is anticipated to increase about 3.5% per year, compared to 2% for the nation on average.[1] Reinstating EE programs will help TEP customers lower their electric bills. For example, prior to the suspension of TEP's Home Energy Reports program in October 2012, the program was serving 25,000 households and was projected to save TEP customers more then 18 GWh. These energy savings are equivalent to ~$1.8 million or ~$70 saved per household in 2012-2013. Any further delay in restoring EE programs would cause additional missed opportunities for TEP customers to save money on their energy costs.

Peak demand for electricity is forecasted to double in Arizona over the next twenty years, 2006-2025, from 16,000 MW to 32,000 MW.[2] Reinstating EE programs will help TEP to better manage its peak demand during the summer period. TEP customers tend to have higher usage spikes during the summer period due to increased temperatures in the region. Home Energy Reports programs in other regions have been shown to drive higher savings (around 1.5 to 2 times) during peak times. Preliminary findings for the TEP program indicate a similar savings trend.

Q: **Explain why the Commission should approve TEP's cost recovery request for its EE programs.**

A: More certain cost recovery for TEP will create additional long-term regulatory certainty for EE companies, allowing them to continue to do business in the state of Arizona. When EE programs are approved without a cost-recovery mechanism in place, regulatory and market uncertainty will follow. In this case, the Commission had approved EE programs, including the Home Energy Reports program. However, the cost-recovery mechanism for TEP to collect EE program funds has not been updated since June 1, 2010. Many of TEP's EE programs have been cut or suspended as a result. Opower commends TEP's proactive approach and good faith effort to reinstate those EE programs. TEP should be allowed to recover those costs so that TEP may continue to carry out EE programs.

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[1] http://www.swenergy.org/programs/utilities/arizona.htm
[2] *Id.*

If the Commission approves TEP's cost recovery request for its EE programs, it will allow TEP to meet its existing commitments with EE businesses and to instill additional market certainty for businesses that serve utilities in meeting their regulatory objectives. TEP customers will also benefit from uninterrupted EE programs that will allow them to better take advantage of energy information, and the incentives associated with other EE program offerings.

Q: Does this conclude your testimony?

A: Yes.

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

PATRICK J. QUINN

ON

SETTLEMENT AGREEMENT

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 14, 2013

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EXECUTIVE SUMMARY

The Arizona Residential Utility Consumer Office ("RUCO") presents the direct testimony of RUCO Director Patrick J. Quinn in support of the Proposed Settlement Agreement on Tucson Electric Power Company's request for a permanent rate increase. Mr. Quinn recommends that the Arizona Corporation Commission adopt the Proposed Settlement Agreement for the following reasons:

The Proposed Settlement Agreement reflects an outcome that is fair to both the consumer and Tucson Electric Power Company and is in the public interest.

The Proposed Settlement Agreement is a comprehensive settlement agreement. Its terms settle a wide range of issues that were of significant interest to several of the intervenors.

RUCO supports the Proposed Settlement Agreement in its entirety because it contains numerous benefits to the consumer which will be discussed in Mr. Quinn's testimony.

The Proposed Settlement Agreement resolves four areas of importance to RUCO in the underlying rate case which included the amount of the rate increase for basic consumers, the net operating loss issue, the depreciation reserve issue and capital expenditures for distribution plant. All of these issues were addressed satisfactorily in the Proposed Settlement Agreement and will be explained more fully in Mr. Quinn's testimony.

INTRODUCTION

Q. Please state your name, occupation and business address for the record.

A. My name is Patrick J. Quinn. I am the Director of the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. I have a BS in Mathematics and a MBA from the University of South Dakota. Additionally, I have 30 plus years of experience in the Telecommunications Industry and the Consulting business dealing with utility regulation. I have testified over 50 times before state and federal regulatory commissions on issues including finance, economics, pricing, policy and other related areas.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain RUCO's support of the Tucson Electric Power Company ("TEP") Proposed Settlement Agreement ("Agreement").

...

Q. Have you participated in other settlement negotiations?

A. Yes. I have participated in settlement negotiations in other matters that have come before the Arizona Corporation Commission ("ACC" or "Commission") both from the utility and consumer side. The majority of these negotiations have resulted in reaching an accord with the utility and the other settling parties, leading to the signing and supporting of a settlement agreement. On the other hand, I have walked away from settlement talks when negotiations produced a result I could not support. I have been involved in three recent negotiations where I represented RUCO. Two have resulted in settlements and the third RUCO found was not in the best interest of residential ratepayers and did not settle. RUCO does not enter into settlements lightly. RUCO will not agree to settle simply as a means of avoiding litigation. However, in this matter, negotiations did produce reasonable and fair terms that RUCO can and does support.

THE SETTLEMENT PROCESS

Q. Was the negotiation process that resulted in the Settlement Agreement a proper and fair process?

A. Yes. The Agreement is the result of numerous hours of negotiation and a willingness among the parties to compromise. The negotiations were conducted in a fair and reasonable way that allowed each party the opportunity to participate. All intervenors had an opportunity to participate in every step of the negotiation. Notice for each scheduled meeting was sent to all parties electronically. Persons were able to participate via teleconference, if necessary. Furthermore, TEP created a secure website that allowed all parties to view all documents submitted as part of settlement negotiations. All parties were allowed to express their positions fully.

On January 18, 2013, Staff filed a Notice of Status and Preliminary Term Sheet which reflected the terms of the negotiations up to that date. The Commission held a Special Open Meeting on January 23, 2013, to review the Preliminary Term Sheet and have the opportunity to ask questions of any of the intervenors. RUCO, along with the other parties, attended the Special Open Meeting and answered questions posed by the ACC Commissioners.

By RUCO's count, 18 parties participated in the Agreement. These participants represent a wide range of interests from mining interests, governmental entities, business and retail interests, industrial interests, low income advocates, union representatives, Commission Staff ("Staff") and RUCO.

Q. Did all the parties sign the Agreement?

A. No. At the very end, a handful of parties choose not to sign the Agreement. These parties have the opportunity to file testimony to explain their reasons why they ultimately did not sign the Agreement.

Q. Why is a negotiated settlement process an appropriate way to resolve this matter?

A. By its very nature, a settlement finds middle ground that the parties can support. All the parties that participated in the settlement talks were sophisticated parties who were well seasoned in the ACC's regulatory processes and veterans of the negotiating table. The fact that so many parties representing such varied interests were able to come together to reach consensus illustrates the balance, moderation and compromise of the document.

Settlement negotiations began only after each party had the opportunity to analyze TEP's Application, file its direct testimony and read the direct testimony of other Intervenors. Of course, the Agreement in no way eliminates the ACC's constitutional right and duty to review this matter and to make its own determination whether the Agreement is truly balanced and the rates are just and reasonable.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. The Agreement reflects an outcome that is fair to both the consumer and TEP and is in the public interest. Furthermore, this is a comprehensive agreement. Its terms settle a wide range of issues that were of significant interest to several of the intervenors.

RUCO supports the Agreement in its entirety because it contains numerous benefits to the consumer. I will list those benefits later. There were four areas of importance that needed to be resolved in the Agreement before RUCO could become a signatory. They were the amount of the rate increase for basic consumers, the net operating loss issue, the depreciation reserve issue and capital expenditures for distribution plant. All of these were addressed satisfactorily in the Agreement and will be explained later in my testimony

SETTLEMENT PROVISIONS

Q. In summary, what are the benefits to the residential consumer?

A. The benefits to the residential consumer are as follows:

- Consumer base rate increase under $3 for the first year. (1)
- Return on equity of 10%, RUCO's recommendation. Resulted in lower revenue requirement than TEP requested. (4.2)

- Credits to customer's bills from the over collected balance in the Purchased Power and Fuel Adjustment Clause ("PPFAC"). (6.1)
- Capping the amount that the Lost Fixed Cost Recovery ("LFCR") mechanism may collect from residential ratepayers to 1% year over year of total company revenues. (8.4)
- Allowing the ratepayer the choice to "opt out" of the LFCR in favor of a higher base rate charge to cover fixed costs.
- The Environmental Compliance Adjustor ("ECA") will have a 0.25% of revenue cap on yearly amount to be recovered. (9.1)
- Annual contribution of $150,000 to benefit low income customers. (12.3)
- Fair rate design for residential customers. (15.1)
- Net Operating Loss docket to be filed. (20.1)
- Depreciation Reserve provision. (20.2)
- Capital Expenditures for Distribution Plant. (20.4)

PUBLIC INTEREST

Q. How is the public interest satisfied by the Agreement?

A. At the most fundamental level, the Agreement satisfies the public interest from RUCO's perspective in that it provides favorable terms and protections for residential consumers as defined above. The Agreement also satisfies the public interest by providing a fair and balanced approach to addressing the Company's concerns on Environmental Protection

Agency ("EPA") required costs, energy efficiency costs and revenue. RUCO believes that providing the Company a narrowly tailored mechanism to recover lost revenue directly and solely associated with Commission-mandated Energy Efficiency ("EE") and Distributed Generation ("DG") programs while providing the ratepayer the ability to opt out of the LFCR with a slightly higher base rate is a reasonable solution to this issue. The Company can meet whatever energy efficiency requirements the Commission sets through the LFCR without shifting the risks of the economy, weather and other factors on to the ratepayer.

FOUR AREAS OF IMPORTANCE

Q. You mentioned four areas of importance that are critical for RUCO to sign on to the Agreement. Would you like to address them?

A. Yes. One of RUCO's main priorities is to analyze monthly rate increases to determine if the increases are in the best interest of the residential ratepayer. Through the negotiation process in this settlement the first year impact on residential consumers will be less the $3.00 a month (3.1). This increase is considerably less than was anticipated at the start of this case. Future years increase will be more than $3.00 but still less than expected.

Q. One of your other areas is the net operating loss issue. Would you please explain what that is?

A. Yes. The accounting treatment associated with net operating loss ("NOL") is an issue in most of the rate cases that have or will be coming before the Commission. This was an issue in this case but because a settlement was reached it was not singularly addressed. The Company has agreed (20.2) to make a filing in the future to ask that a generic docket be opened to address this issue going forward. The generic docket on NOL would be the proper time to discuss the myriad of accounting issues that need to be resolved for future rate cases.

Q. Another concern is the issue on depreciation reserves. Please explain this issue.

A. In TEP's analysis of its depreciation reserves it was noted that there was excess depreciation. Excess depreciation occurs when the actual and theoretical depreciation lives are different. There was no disagreement between the Company and RUCO on the amount. The only issue was how fast the excess depreciation should be given back to the consumer and in what form. In the negotiation process, a resolution was reached in the Agreement (20.3) that allows for two possible ways of passing the excess depreciation on to the consumers in the future. This solution is in the best interest of the consumers and the Company.

Q. What is your last area of concern and would you explain it?

A. Yes. There are a number of factors that have been introduced into the generation environment. The Commission has required that companies like TEP reach a certain level of generation by renewable forms of energy. Energy efficiency programs have been put in place and the EPA is setting further requirements on companies to clean up coal plant emissions. All of these factors, as well as normal operations, require the Company to invest capital in plant. One of the issues in this case concerned the Company's capacity requirements. RUCO thought that it and Staff could get a better understanding of capital expenditures made by the Company if we had annual presentations by the Company on their future capital expenditures. Section 20.4 of the Agreement provides for that. This will be of great help to RUCO for future evaluations of the Company's operations.

Q. Regarding these four areas were there any that were more critical to RUCO's becoming a signatory?

A. Yes. The NOL and Depreciation Reserve needed to be resolved before RUCO could sign on and they were in the Agreement.

Q. Does this conclude your testimony on the Agreement?

A. Yes it does.

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

REDACTED DIRECT TESTIMONY

OF

FRANK W. RADIGAN

AND

PAUL GOETZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 21, 2012

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EXECUTIVE SUMMARY

Based on our analysis of Tucson Electric Power Company's ("TEP" or the "Company) rate application, we have concluded the following:

The Company has failed to justify all of the increase in plant in service since the last rate case and we recommend that the net plant in service be reduced by approximately $167 million and test year depreciation expense by approximately $3.9 million. The impact on the revenue requirement from this adjustment is approximately $21 million. We should note that RUCO continues to gather information on the Company's budget process and supporting justification. RUCO leaves open the possibility to revise this adjustment to plant in service when it files its direct testimony on rate design on January 7, 2013 if it receives acceptable supporting documentation from the Company.

Based on our depreciation reserve analysis, which provides a metric of the accuracy of past depreciation rates, we have concluded that the theoretical reserve is higher than the book reserve meaning that depreciation expense has been overstated in the past and the Company accrued too much money from ratepayers.

There is a great deal of uncertainty around the timing, cost, and outcome of compliance with present and possible future environmental rules that might impact the Company's generating units, especially the coal fired generating units. There are also many possibilities as to what the eventual compliance with these regulations may be, including the potential for shutting down San Juan Units 1 & 2, where the Company expects to make the largest capital investment over the next few years.

INTRODUCTION

Q. MR. RADIGAN, PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the utility industry, specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. PLEASE DESCRIBE THE HUDSON RIVER ENERGY GROUP.

A. The Hudson River Energy Group ("HREG") is an engineering consulting firm specializing in the fields of rates, planning, economics and utility operations for the electric, natural gas, steam and water utility industries. HREG was founded in 1998 and has served a wide variety of clients including municipal utilities, government agencies, state commissions, consumer advocates, law firms, industrial companies, power companies, and environmental organizations. HREG conducts rate design and cost of service studies, and designs performance-based rate plans. HREG also assists clients in handling the complexities of deregulation and restructuring, including Open Access Transmission Tariff pricing, unbundling of rates, resource adequacy, transmission planning policies, and power supply.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now known as "Clarkson University") in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service Commission ("NYPSC") in the Rates and System Planning sections of the Power Division. My responsibilities included, resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the state. These duties also encompassed rate design, performing embedded and marginal cost of service studies, as well as depreciation studies.

Before leaving NYPSC, I was responsible for directing all engineering staff during major proceedings, including those relating to rates, integrated resource planning, and environmental impact studies. In February 1997, I left NYPSC and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own company.

In my 31 years of experience, I have testified as an expert witness in utility rate proceedings on more than 100 occasions before various utility regulatory bodies, including: the Arizona Corporation Commission, the Connecticut

Department of Public Utility Control, the Delaware Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, New York Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Pennsylvania Public Utilities Commission, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the FERC. Currently, I advise a variety of regulatory commissions, consumer advocates, municipal utilities, and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A copy of our resumes is attached as Exhibit__FWR/PG-1.

Q. MR. GOETZ, PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Paul Goetz. I am a partner in the firm of Bollam, Sheedy, Torani, & Company which is a multi-disciplinary certified public accounting and management consulting firm offering accounting, auditing, tax, and management consulting solutions 26 Computer Drive West, Albany, NY.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I have a Bachelor's Degree in Business Administration from Siena College, and currently serve on the Dean's Advisory Council at the Siena College School of Business. I am a New York State Certified Public Accountant with over 25 years of accounting and financial consulting experience. I have been a partner since 2011 where I serve as a member of the Governmental Services Group. Prior to that I served as the Managing Director of UHY Advisors, beginning in 1985.

I have extensive background in accounting, auditing and consulting, having garnered experience in commercial and governmental enterprises. I have done numerous contract audits on behalf of several state departments of transportation including Arizona, Connecticut, Delaware, New York and Vermont. I regularly advise governmental agencies and authorities on various accounting and regulatory matters. I have testified before a number of regulatory bodies relating to management audits, accounting, and property record reconstruction for villages and municipalities throughout NY, as well as for numerous public utilities.

Q. FOR WHOM ARE YOU APPEARING?

A. We are testifying on behalf of the Residential Utility Consumers Office ("RUCO").

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. We have been asked to review the justification in support of the increase in plant in service from the last rate case; the justification and allocation of the cost of the new headquarters building at 88 Broadway, Tucson; the Company's depreciation study; and the justification for the Company's proposed Environmental Compliance Adjustor ("ECA") and the Company's proposal to add post test year plant to rate base.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, we have prepared the following exhibits:

Exhibit FWR/PG-1 Resumes of Frank Radigan and Paul Goetz

Exhibit FWR/PG-2 Response to RUCO 6.7

Exhibit FWR/PG-3 Response to RUCO 9.1 with Sample Attachment

Exhibit FWR/PG-4 21st Street Transformer

Exhibit FWR/PG-5 Response to RUCO 7.13 without Attachments

Exhibit FWR/PG-6 Extract from Attachment to Response to RUCO 7.13, August 2008 Presentation

Exhibit FWR/PG-7 Extract from Attachment to Response to RUCO 7.13, October 2010 Presentation

Exhibit FWR/PG-8 RUCO 7.03

Exhibit FWR/PG-9 RUCO 7.04

Exhibit FWR/PG-10 RUCO 7.06 and Excerpt from Attachment to RUCO 7.13

Exhibit FWR/PG-11 RUCO 7.06, 7.07 & 7.08

Exhibit FWR/PG-12 Excerpt from Attachment to RUCO 7.13, August 2010 Presentation

Exhibit FWR/PG-13 Excerpt from Attachment to Response to RUCO 7.13, May 2011 Presentation

Exhibit FWR/PG-14 RUCO 7.23

Exhibit FWR/PG-15 UNS Headquarters Brochure

Exhibit FWR/PG-16 Excerpts from UNS 10-Ks for 2009 and 2010

Exhibit FWR/PG-17 Tucson Office Space Cost

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

As such, the Company has failed to justify all of the increase in plant in service since the last rate case and we recommend that the net plant in service be reduced by approximately $167 million and test year depreciation expense by approximately $3.9 million. The impact on the revenue requirement from this adjustment is approximately $21 million. We should note that RUCO continues to gather information on the Company's budget process and supporting justification. RUCO leaves open the possibility to revise this adjustment to plant in service when it files its direct testimony on rate design on January 7, 2013 if it receives acceptable supporting documentation from the Company.

[BEGIN CONFIDENTIAL

END CONFIDENTIAL]

A deprecation reserve analysis compares what is recorded on the books of the utility - the book reserve - with the theoretical reserve. The book reserve is what the utility collected from ratepayers through depreciation rates and the theoretical reserve is a calculation of what the depreciation reserve "should be" based on the current estimates of average service life, survivor curves, and net salvage estimate. The reserve analysis provides a metric of the accuracy of past depreciation rates: if the theoretical reserve is higher than the book reserve, it means that the past depreciation parameters have overstated depreciation expense and the Company accrued too much money from ratepayers. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

There is a great deal of uncertainty around the timing, cost, and outcome of compliance with present and possible future environmental rules that might impact the Company's generating units, especially the coal fired generating units. There are also many possibilities as to what the eventual compliance with these regulations may be, including the potential for shutting down San Juan Units 1 & 2, where the Company expects to make the largest capital investment over the next few years. The Company argues that the reasonableness of its actions can be seen in its Integrated Resource Plan ("IRP") but, as described more fully in testimony, reliance on the IRP process is inadequate to address these issues as the IRP process itself could use improvement; in the last IRP the Company itself noted that it was only a "snapshot in time". Regulatory lag aligns the interests of the utility and ratepayers so as to encourage the utility to make the least-cost option available to it. There is nothing presented by the Company in this case that shows the ECA would better align the interests of ratepayers and shareholders. In fact, since the utility would know that it would be fully compensated no matter the outcome of complying with environmental regulations, there is a real risk that the ECA could result in higher costs to ratepayers rather than lower. While there may be some level of expenditures that could be supplied to the utility between rate cases such as what is granted to Arizona Public Service Company ("APS"), the amount of money being requested here goes well beyond that. Based on all of the above, we do not recommend its adoption as currently proposed by the utility at this time.

The Commission has ruled that post test year plant additions are generally not allowed unless extraordinary circumstances are shown to exist. As discussed above, by disallowing costs made between rate cases, it puts financial pressure on the utility to minimize costs. We would note that the utility has provided no evidence that extraordinary circumstances exist, but it does point out that Arizona Public Service Company ("APS") was able to recover post test year plant in its last rate case. The last APS rate case was a settlement and not fully adjudicated. As such, RUCO does not support post test year plant additions other than those for the Company's solar projects. RUCO supports the addition of the solar projects because it recognizes the commitment the Arizona Corporation Commission and other branches of Arizona state government have made to encourage the expansion of solar powered generation.

PLANT IN SERVICE PROGRAM

Q. PLEASE DISCUSS THE GROWTH IN THE COMPANY ASSET BASE SINCE THE LAST RATE CASE.

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

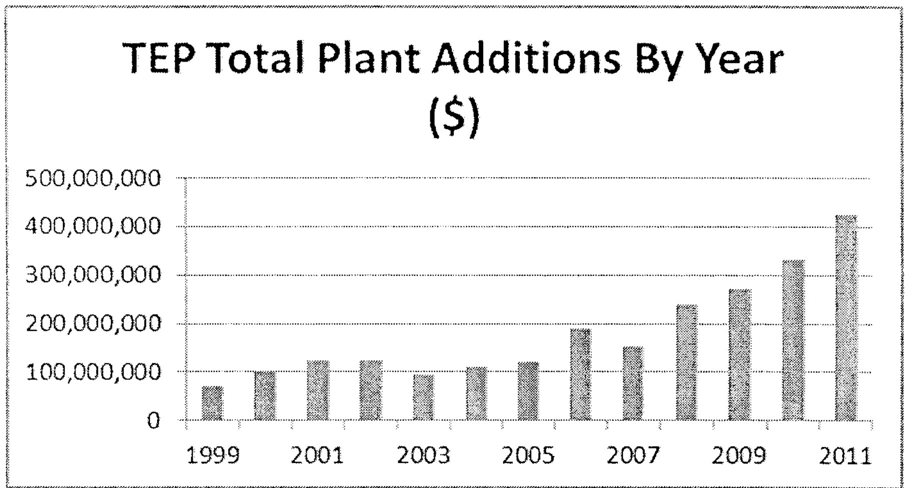
Q. HOW DOES THE GROWTH IN PLANT COMPARE TO GROWTH IN RETAIL SALES AND NUMBER OF CUSTOMERS?

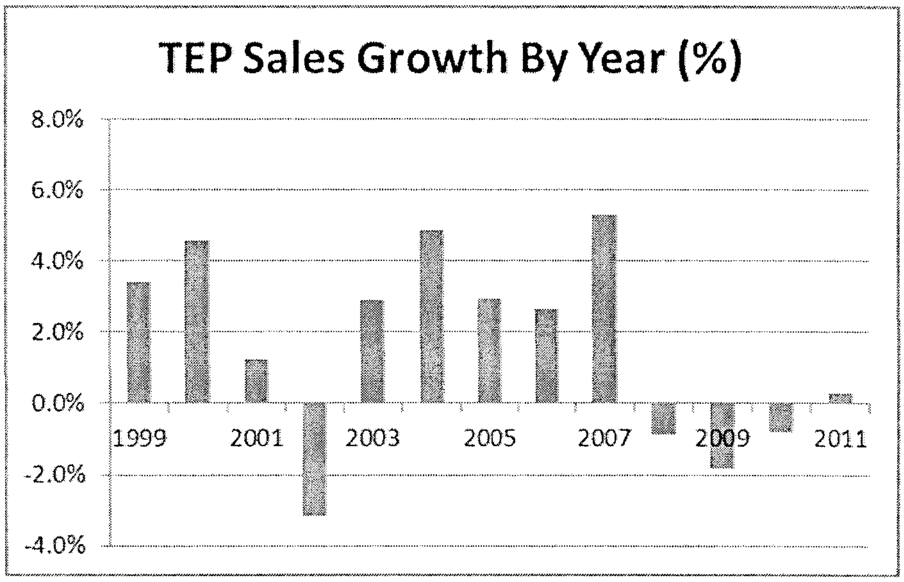
A. They are directly opposite. As testified to by Company witness Bonavina:

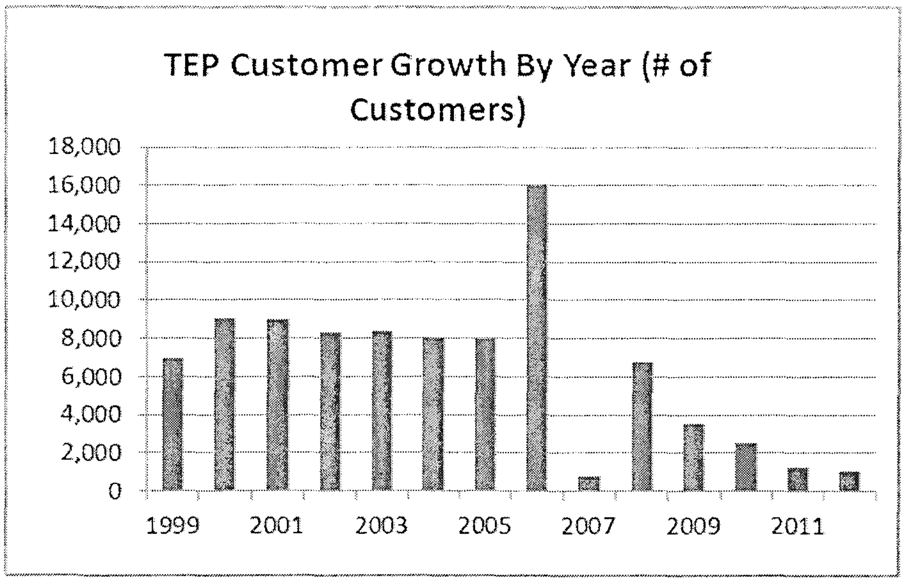
> TEP's retail sales had increased at a greater than 3 percent annual rate for five successive years, including a 4.7 percent jump in 2007 (Bonavina Direct at page 5)

> The Company's retail energy sales fell by 3.1 percent from 2007 to 2011 and are expected to drop another 0.7 percent in 2012. The downturn in Arizona's housing market and the increase in the unemployment rate combined to slow the traditional growth of TEP's retail customer base. After expanding at an average annual rate of 2.3 percent between 2000 and 2007, TEP's customer base grew by less than one percentage point in each of the last four years (Bonavia Direct at page 6).

The dramatic differences between spending growth and sales and customers growth are clearly illustrated by the graphs below that were assembled using data reported in TEP's FERC Form 1.







Q. ARE DIFFERENCES BETWEEEN SPENDING GROWTH AND SALES GROWTH IMPORTANT?

A. Yes, regulated utilities are allowed to recover a return on investment that is "used and useful". As such, if the utility builds a distribution substation, the substation must be connected to the transmission system and used to provide useful service to the utility's ratepayers. Building new capacity for new customers is beneficial to the utility since the average residential customer uses almost 11,000 kWh per year and the net revenues from the customer is approximately $750 per year. While that is a small amount for one customer, one must consider that a new 2,500home subdivision might bring in as much as $1.8 million in revenues per year and support approximately $14 million in new plant investment for the utility. From the ratepayer point of view, capacity planning at the substation is important: if the utility builds a substation too large, it will be only partially used and partially useful, and the question must arise of how much of the cost of the substation should be allowed in rates in any given rate proceeding. As such, a review of the utility's capital budget process is important to determine what the utility was building for and how it was to be used.

Q. WHAT IS THE PROCESS BY WHICH THE COMPANY PLANS ITS CAPITAL BUDGET PROGRAM?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. HAVE YOU BEEN ABLE TO REVIEW THE DETAIL TO WHICH COMPANY PERSONNEL JUSTIFIES A CAPITAL PROJECT TO THE MANAGEMENT OF THE COMPANY?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WAS YOUR INVESTIGATION ONLY LIMITED TO TRANSMISSION AND DISTRBUTION EXPENDITURES?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHAT TYPE OF SUPPORT WOULD YOU EXPECT THE COMPANY TO PROVIDE AND WHY IS THAT INFORMATION IMPORTANT?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

One should note that the utility has many options to deal with a transformer that is overloaded. It can let the transformer operate that way provided the condition is only a few hours of the year, or it can transfer load to another substation (sometimes at very little cost). In this case, it is important to note that the addition of the second transformer was for future load.

A scenario such as this demonstrates how a seemingly routine action by the Company can potentially lead to confusion in the matter of cost justification, and why it is crucial for the Company to provide support for such everyday actions. If the new transformer was sized and rated to meet future load, ratepayers might question why they should be asked to pay for the project at the present time when such load is not needed. If the load does in fact materialize in the future, the Company will benefit by having one set of customers pay for the upgrade while another provides excess revenues. On the other hand, if the load does not materialize, ratepayers might surmise they are paying for what appears to them to be the Company's inaccurate planning.

[BEGIN CONFIDENTIAL

[END CONFIDENTIAL]?

Q. PLEASE DISCUSS THE IMPORTANCE OF CAPITAL BUDGETING.

A. Capital budgeting is critical to regulated capital intensive companies. The process must be rigorous to minimize consumer costs while maintaining a high level of reliability. As described below, the process is inherently extensive and complex. Because of its importance both for forecasting cash flow and for optimizing limited financial resources, the process needs to be extensively documented. In this case, the inability to obtain support for the process and justification of major expenditures is surprising and contradictory to normal practices.

A description of such normal practices is excerpted here from *Accounting for Public Utilities,* Robert L. Hahne and Gregory E. Aliff, LexisNexis updated through #27, November 2010:

> *Section 15.02 page 15 – 11*
>
> The unique characteristics of utility planning are as follows:
>
> - The capital-intensive nature of the utility industry leads to a heavy emphasis on capital budgeting (which often starts a few months earlier that expense budgeting) and I'm budgeting maintenance cost parenthesis I PAET., Costs for preventative and corrective maintenance and outages).
>
> - Annual and long-term production and transmission capacity planning is of major importance. Because of the variety of electricity and gas sources now made available by technological, regulatory, and economic changes, "make versus buy" decisions have become a part of the capacity planning process. Electric utility practices such as demand-side management and conservation marketing Harolds so provide alternatives to building new capacity. The arrival of market measures has affected these planning activities resulting in some surprising market anomalies. In addition, the greater interest in "green energy" And "sustainable energy" production is creating further planning challenges, as "green power" initiatives has) parenthesis usually) a different supply profile, higher degrees of interrupt ability of supply, advantageous tax regimes and many consumers may well pay a premium for "green power". Planning for impacts and opportunities associated with the "smart grid" and transmission distribution

systems system upgrades adds a further complexity.

Pages15-13, -14, and -15

The planning process often includes the following major tasks.

--Examined business environment and company capabilities.

--Review/develop strategic plan.

--Develop overall operating and financial plan.

--Are planning and budgeting instructions.

--Prepare functional action plans.

--Prepare responsibility area budgets.

--Consolidate area budgets.

--Prepare pro forma financial statements.

--Evaluate regulatory impact.

--Resolved an approved budgets.

The planning process is supported by planning models.

Q. HAS THE COMPANY MET ITS BURDEN OF PROOF THAT ITS ACTIONS WERE JUSTIFIED?

A. No. Based on our review of the Company's capital budget process, we find that while the Company states that it has a reasonable means to assemble and cost justify individual projects, it cannot show that it does so. This does not mean that the justification does not exist, but rather in the course of this adjudicated proceeding it could be there was just a simple miscommunication as to the information desired versus the information provided. In an effort to fully develop the record in this case, RUCO is still trying to gather information on the Company's budget process and supporting justification. RUCO leaves open the possibility to revise this adjustment to plant in service when it files its direct testimony on rate design on January 7, 2013 if it receives acceptable supporting documentation from the Company.

Q. WHAT DO YOU RECOMMEND?

A. The two largest budget categories are for Production and Transmission & Distribution. Based on the support provided, we recommend that only the amount of plant that has been supported as needed be allowed in rate base. The Company reports several budget categories are done under blanket work orders which are based on historical spending levels or for public policy and largely outside of their direct control (renewable and solar). Also, while no cost justification for expenditures on transmission projects have been provided in this proceeding, the Company does provide some cost information to the Transmission Line Siting Committee. While Transmission Plan is not a subject of this proceeding, for budget purposes it is reported along with distribution so it impacts the review process. As we said previously, RUCO is still gathering information and we hope that the Company can provide justification beyond what they already have; we have covered under blanket work orders.

The final adjustment therefore is meant to reflect no support for projects over which they have direct control and for which they should have been able to provide justification. The process was implemented to reduce the amount of plant that has been added to rate base since the end of 2006. This reduces gross plant and allows a recalculation of the depreciation reserve and depreciation expenses, thereby resulting in a new net plant figure. . We believe that this is the only reasonable means to implement an adjustment to reflect a lack in support for expenditures made. In dollar terms, this recommendation results in a reduction in gross plant of $162 million out of the approximately $900 million that the Company has added since 2006. Put another way this adjustments disallows, for lack of support, 18% of the expenditures made. The impact on the revenue requirement from this adjustment is approximately $21 million.

NEW HEADQUARTERS BUILDING

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW HEADQUARTERS BUILDING.

A. In the current rate case, TEP states that it has invested approximately $92 million related to construction of a new headquarters building in downtown Tucson (DeConcini Direct at page 26). The Company states that the new building has alleviated significant overcrowding at TEP's campus on East Irvington Road where hundreds of employees were working in trailers separating them from other related workgroups (Ibid). The Company also states that though the up-front cost associated with building a new corporate headquarters is significant, customers will realize significant and measurable benefits in the long term (DeConcini Direct at page 27). Finally, the Company states that the new building also allowed them to bring more than 500 employees together in a dedicated work environment that was built for their specific business needs (Ibid).

Q. WHAT ARE THE BENEFITS THE COMPANY CLAIMS WILL BE REALIZED WITH THE NEW BUILLDING?

A. Based on the explanation offered by the Company, it appears that the most important benefits are an improved work environment for employees and that the new building allows employees to work more efficiently (DeConcini Direct at page 27). The improved work environment comes from the fact that the work facilities at Irvington Road were old and in need of improvement. The improved efficiency comes from the fact that instead of having some employees located downtown and some located at Irvington Road, all employees are now assigned to offices in the same areas of the building, making it much easier to communicate and collaborate while saving travel time.

Q. PLEASE PROVIDE SOME BACKGROUND ON WHY A NEW HEADQUARTERS BUILDING WAS PLANNED?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. DID UNS EXAMINE MANY OPTIONS IN DECIDING WHERE TO LOCATE ITS NEW HEADQUARTERS BUILDING?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHEN DID THE COMPANY FIRST CONSIDER HOUSING MORE THAN JUST CORPORATE FUNCTION EMPLOYEES IN THE BUILDING?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. PLEASE DISCUSS THE IRVINGTON ROAD FACILITY

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. ARE YOU AWARE OF ANY OTHER FACTORS THAT IMPACTED THE CONSTRUCTION OF THE NEW HEADQUARTERS BUILDING?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. New Market Tax Credits are a Federal program to incent investment in low-income communities. The New Market Tax Credit Program was established in 2000. The credit program is incorporated in Section 45D of Internal Revenue Code. The program allows for the receipt of credit against Federal Income taxes for making Qualified Equity Investments (QEI) in qualified community development entities (CDE's). The program was established with the expectation of creating jobs and making material improvement in the lives of residents of low-income communities or populations.

A qualified equity investment is defined as an investment into a Community Development Entity (CDE). The CDE enters into an allocation agreement with the Community Development Financial Institutions Fund (CDFI) who provides allocations of New Market tax credits to CDI's allowing them to attract investments from the private sector to be reinvested in low income communities

The program provides for credits equal to 39% of the investment into the CDI. The credit is provided over a seven years and is equal to 5% of the qualified investment in Years One-Three and 6% of the qualified investment in Years Four-Seven. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHEN DID THE COMPANY REALIZE THAT IT WOULD NOT BE GETTING THE NEW MARKET TAX CREDIT?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHEN DID UNS TRANSFER OWNERSHIP OF THE NEW HEADQUARTERS BUILDING TO TEP?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPANY'S DECISION MAKING PROCESS?

A. The facts are clear the new headquarters building was conceived as a corporate headquarters for UNS and not for TEP. The original plan and design of the building was just to bring employees with corporate duties together under one roof. That the new building is the headquarters of the UNS Corporation is still the building's main function. Brochures in the lobby of the new building describe the building as "UniSource Energy's solar-powered energy-efficient Tucson headquarters" and declare the corporate headquarters "a showcase of green construction and design" (Exhibit__FWR/PG-15 UNS Headquarters Brochure).

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHAT ARE THE RATEMAKING IMPLICATIONS OF THE NEW HEADQUARTERS BUILDING BEING PRINCIPALLY BUILT FO+R CORPORATE PURPOSES?

A. Docket No. U-1933-97-176[1] was the proceeding whereby Tucson Electric Power Company was allowed to form a Holding Company. In that proceeding, the Company proposed 17 conditions as safeguards to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. In approving the petition, the Arizona Corporation Commission imposed several more safeguard conditions and approved those proposed by the Company. One of the original safeguard conditions was as follows:

> The Holding Company, TEP and sister companies will strive to charge the lower of fully allocated cost or market price whenever goods, products or service are sold/provided by the Holding Company or sister companies to TEP and the higher of fully allocated cost or market whenever TEP sells/provides non-tariffed goods, products or services to the Holding Company or sister companies. The Holding Company, TEP and sister companies recognize that determining a market price for all goods, products and services being transferred in and among the Holding Company, TEP and sister companies could be a complex or difficult task for some items. Nonetheless, the Holding Company, TEP and sister companies agree to attempt to determine a market price for any good, product or service being provided by TEP to the Holding Company or sister companies as well as for any good, product or service provided by Holding Company or sister companies to TEP whenever the annual, fully allocated cost for given good, product or service being transferred exceeds $500,000 annually. Furthermore, TEP will retain such market research information (regardless of whether it is ever utilized) until such time as the Utilities Division Staff or its representative have reviewed such information.

The implications of these safeguard conditions are clear: had UNS continued to own the new headquarters building it would not be allowed to charge any more than market rates for rent. If TEP owned the building, however, it would

[1] Docket No. U-1993-97-176, In the matter of the Notice of Intent of Tucson Electric Power Company to Organize a Public Utility Holding Company and for Related Approvals or Waivers Pursuant to R14-2-1801, ET SEQ., Decision No. 60480 issued November 25, 1997.

be allowed to charge the higher of embedded cost or market rates. In other words, if the cost of the new building exceeded the market rate, TEP should own the building; if the cost of the new building was less than the market rate, the holding Company became indifferent to who owns the building.

Q. WHAT IS THE FULLY ALLOCATED COST OF THE NEW HEADQUARTERS BUILDING AND THE MARKET RATE FOR OFFICE SPACE IN DOWNTOWN TUCSON?

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. Published market rates for a full service lease for Class A office space in downtown Tucson is $25 per square foot of rentable office space and $12 per square foot outside of downtown (Exhibit__FWR/PG-17 Tucson Office Space Cost).

Q. WHAT DO YOU RECOMMEND BE DONE IN THIS PROCEEDING?

A. [BEGIN CONFIDENTIAL

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[2] A full service lease includes the cost of operation and maintenance expense as well as property taxes.

END

CONFIDENTIAL].

DEPRECIATION RESERVE ANALYSIS

Q. WHAT IS DEPRECIATION?

A. According to the Supreme Court of the United States:

> Broadly speaking, depreciation is the loss; not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy and obsolescence. Annual depreciation is the loss which takes place in a year.[3]

Another commonly cited definition comes from the American Institute of Certified Public Accountants which defines depreciation as follows:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

Q. WHAT IS DEPRECIATION EXPENSE?

A. The depreciation expenses of a utility are determined by applying approved depreciation rates to the depreciable plant balances. The rates are developed

[3] *Lindheimer v. Illinois Bell Telephone Company*, 292 U.S. 151, 167 (1934).

separately for particular classes of plant, such as production (e.g., gas-fired generation, coal-fired generation), transmission, distribution, etc., based on detailed studies.

Q. WHAT IS THE DEPRECIATION RESERVE?

A. While depreciation expense represents the annual recovery of the capital investment, there is another depreciation category that records all depreciation expense, retirements, cost of removal and gross salvage on a continuous basis. This account is the accumulated provision for depreciation, also known as the depreciation reserve. The depreciation reserve serves as a "running total" of the extent to which individual assets or groups of assets have been depreciated. In a depreciation study, the depreciation reserve is known by several other names as well, the most notable being the "book reserve", the "recorded reserve" or the "actual reserve".

Q. WHAT IS THE THEORETICAL RESERVE?

A. The theoretical reserve is the amount of money that should have been accrued had the depreciation parameters been in effect for all plants since it was installed. The theoretical reserve can be calculated using current depreciation parameters (service life, life table, and net salvage), or proposed parameters in the case of a new depreciation study.

Q. WHAT IS A DEPRECIATION RESERVE ANALYSIS?

A. A deprecation reserve analysis compares what is recorded on the books of the utility - the book reserve - with the theoretical reserve. The theoretical reserve is a calculation of what the depreciation reserve "should be", based on the current estimates of average service life, survivor curves, and net salvage estimate. The comparison between the book reserve and the theoretical reserve provides a metric of the accuracy of past depreciation rates.

If the theoretical reserve is higher than the book reserve it means that the past depreciation parameters have overstated depreciation expense and the Company accrued too much money. If the theoretical reserve is lower than the book reserve it means that the past depreciation parameters have understated depreciation expense and the Company accrued too little money.

Q. HOW ARE DIFFERENCES IN THE BOOK RESERVE AND THEORETICAL RESERVE TREATED UNDER THE COMPANY'S STUDY?

A. The Company is using the "remaining life technique" to recover any differences. When using the remaining life technique, depreciation expense is calculated by determining how much of a depreciation reserve is required and then subtracting the book reserve from that amount. The result is the amount of money that needs to be accrued in the future. This future accrual is then divided by the remaining life to get the annual depreciation expense.

Thus, as the calculation takes into account both how much money has already been accrued and how much must be accrued in the future, the remaining life technique is self-correcting with respect to differences in book-to-theoretical reserves. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. IS THE COMPANY'S METHODLOGY FOR TREATMENT OF RESERVE IMBALANCES THE ONLY OPTION?

A. No. There are times when the differences are so large that this self-correcting feature of the remaining life technique is considered too long a period to recover differences in the book to theoretical reserve. When that happens, an amortization of the difference or a portion of the difference is either collected or passed back to ratepayers over a shorter period of time.

Q. CAN YOU PROVIDE CITATION FOR DIFFERENT TREATMENTS OF RESERVE IMBALANCES?

A. Yes. The National Association of Regulatory Utility Commission ("NARUC") has published a manual on depreciation practices for use primarily by staff of the various public utility commissions. The purpose of this resource is to present background material and operating practices for the determination of depreciation of public utility property in matters of regulation. The manual, entitled "Public Utility Depreciation Practices" published in 1996 states at page 188:

A reserve imbalance exists when the theoretical reserve is either greater or less than the actual reserve. If changes are made to the estimated service life and net salvage, creating a reserve imbalance, a decision must be made as to whether and how to correct the reserve imbalance. Should the imbalance be amortized (debited or credited) to the current depreciation expense over a short period of time; or should a remaining life depreciation rate be used to spread the imbalance over the future remaining life of the plant; or should future depreciation rates be adjusted to reflect the current estimated service life of the plant leaving the decision to adjust the reserve for the future? Further analysis will provide additional information to assist in making these decisions.

When a depreciation reserve imbalance exists, one should investigate why past depreciation rates, average service lives, salvage, or cost of removal of removal amounts differ from current estimates. Care should be taken to analyze these effects before correcting for the reserve imbalances. Instances will occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known. Recognizing the nature of depreciation and its requirement for future estimations, no adjustment in annual depreciation accruals to reflect a reserve requirement, based on current rates, should be made unless there is a clear indication that the theoretical reserve is materially different from the book reserve.

Whereas the judgment of materiality is subjective, if further analysis confirms a material imbalance, one should make immediate depreciation accrual adjustments. The use of an annual amortization over a short period of time or setting of depreciation rates using the remaining life technique are two of the most common options for eliminating the imbalance. The size of the plant account, the reserve ration, the account remaining life, the technology of the plant in the account, and the account reserve imbalance in relationship to the account annual accrual all have a bearing on the chosen course of action.

Q. CAN YOU PROVIDE EXAMPLES FOR DIFFERENT TREATMENT OF RESERVE IMBALANCES?

A. Yes. In two recent cases, the Florida Public Service Commission ("FPSC") found that there were significant levels of excess reserves for the utilities before them and that the levels represented too great a level of intergenerational inequity[4]. In each of these cases, the FPSC ordered four-year amortizations of the excess reserves.[5]

In another recent case in Connecticut, the issue of large over-accruals was also addressed. There the Connecticut Department of Utility Control (now the Connecticut Public Utilities Regulatory Authority) found that since the reserve imbalance was large, some sort of accelerated amortization of the depreciation reserve returned to ratepayers in the near term would be fair to both customers and the Company[6]. As such, the Connecticut Department of Utility Control ordered a pass back of the excess reserve over a seven year period[7].

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[4] A situation where the current generation pays and future generations enjoy the benefit.

[5] FPSC Order No. PSC-10-1053-FOF in Docket No. 080677-EI - Petition for increase in rates by Florida Power & Light Company and Docket No. 090130-EI - 2009 depreciation and dismantlement study by Florida Power & Light Company, issued March 17 2010, Order at page 87; and FPSC Order No. PSC-10-0131-FOF-EI -- Docket No. 090079-EL --Petition for increase in rates by Progress Energy Florida, Inc., et. al., issued March 5, 2012, Order at page 52.

[6] Docket No. 09-12-05, Application of the Connecticut Light & Power Company to Amend its Rate Schedules, Final Decision issued June 30, 2010, page 76.

[7] Ibid.

Q. WHAT ARE THE BOOK AND THEORETICAL RESERVES FOR TEP?

A. BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. WHAT WERE THE BOOK AND THEORETICAL RESERVES FOR TEP IN THE COMPANY'S LAST DEPRECIATION STUDY?

A. The details are provided in Statement C of the 2007 Depreciation Rate Study as presented as Exhibit KAK-1 to Company witness Kateregga's testimony in Docket No. E-O1933A-07-0402. For December 31, 2006, the total recorded book reserve for the Company was $1,024,972,639 and the theoretical reserve was $721,458,451, for a difference of $303,514,188.

Q. DO YOU BELIEVE ANYTHING SHOULD BE DONE WITH THE DIFFERENCE IN BOOK AND THEORETICAL RESERVE IN THIS CASE?

A. Yes, it should be returned to ratepayers. While there is no general rule of thumb or industry standard on pass back of reserve imbalance, in our experience, given that depreciation studies contain so many accounts, parameters and assumptions, if the difference between the book and theoretical reserve is +/- 10% then no adjustment should be made as this level of reserve imbalances is within the range of reason[8]. When the reserve imbalance is larger than +/- 10% one should consider a pass back or collection to get the book and theoretical reserves in balance again; balancing the book and theoretical reserves assures ratepayers and stockholders that the depreciation expenses being charged are fair and reasonable. The timing of the pass back or collection of the reserve imbalance is subject to the amount of the reserve imbalance. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

With all of this in mind, we recommend that the reserve imbalance be reduced to +10 percent with the difference returned to ratepayers in an accelerated manner, and further recommend a pass back of six years. This recommendation reduces the revenue requirement very conservatively by approximately $21 million.

[8] In the case in Connecticut the reserve imbalance was a 55% over accrual and in the cases of Florida Power and Light the reserve imbalance was $1.2 billion or approximately 10% over accrued.

ENVIRONMENTAL COMPLIANCE ADJUSTOR

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL FOR AN ENVIRONMENTAL COMPLIANCE ADJUSTOR?

A. The Environmental Compliance Adjustor ("ECA") is a proposal for a mechanism that would allow TEP to recover the costs required to meet environmental compliance standards imposed by federal or other governmental agencies. TEP is proposing the implementation of the ECA in this rate case in response to an ever-increasing number of rules creating more stringent environmental standards that require the Company to invest an unprecedented amount of capital in its generation resource portfolio over the next five years (Hutchens Direct at page 23). Company Witness Hutchens provides the reasoning behind the ECA and Company Witness Jones is sponsoring the details to the ECA adjustor mechanism itself.

Q. PLEASE SUMMARIZE THE COMPANY'S REASONS FOR THE ECA?

A. Depending on the final outcome of certain proposed regulations, TEP's total capital outlays could approach $400 million, in addition to annual increases in O&M costs in the tens of millions of dollars (Hutchens Direct at page 25). TEP will not be able to phase-in or control the timing of these costs, as the compliance deadlines are mandated exclusively by the EPA and judicial rulings (Ibid).

The Company states it is likely most of the expenditures discussed above will occur between rate cases (Hutchens Direct at page 25). For TEP, these environmental mandates will result in reduced cash flow and increased capital and O&M expenditures without recovery of those costs through increased revenue because of the extended time between the adjudication of TEP rate cases (Ibid). If this occurs, it will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms (Ibid). For TEP's customers, absence of the ECA will negatively impact them because the accumulated capital costs and increased O&M will result in larger rate increases (Ibid).

Company Witness Hutchens states that the availability of an ECA to recover environmental compliance costs as they incur - between rate cases – is preferable, as they would lead to more moderate annual rate increases (Hutchens Direct at page 26). Otherwise, Mr. Hutchens opines that TEP's financial health will suffer and its customers will have to absorb large rate increases following the adjudication of multiple general rate cases (Ibid).

Q. WHAT TYPES OF ENVIRONMENTAL PROJECTS WOULD BE COVERED UNDER THE ECA?

A. In general, the aforementioned environmental standards apply to, but are not limited to, the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals, and water intake (Exhibit CAJ-6, page 1). Some of the types of regulations that could be covered by the ECA are those that impact regional haze mandates, mercury emissions, greenhouse gases, and ozone standards (Hutchens Direct at page 24). The cost to comply varies from plant to plant, from a low of a $5 million capital upgrade at Springerville to a high of a $200 million capital upgrade at the San Juan Generating Station (Hutchens Direct at pages 25 and 24 respectively).

Q. PLEASE DISCUSS THE MECHANICS OF HOW THE ECA WOULD WORK?

A. Company Witness Jones states that the investments that qualify for the ECA shall be those projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations (Exhibit CAJ-6, page 1). For these qualified investments, the Company will be allowed a return (based on TEP's Weighted Average Cost of Capital approved by the Commission), depreciation expense, income taxes, property taxes, operation and maintenance expenses, and deferred taxes and tax credits where applicable (Jones FT at page 62). The Company will also be allowed to get a return for ECA qualified investments prior to the in-service date ("CWIP") (Ibid at page 63).

TEP will submit a filing supporting its ECA rate with the Commission on March 1 of each year. TEP proposes that the ECA rate adjustment become effective on May 1st following the March filing, unless suspended by the

Commission (Ibid). The Commission may review the capital expenditures and other costs related to environmental compliance with the annual ECA filing and within the context of a rate case to determine prudency (Ibid). The Integrated Resource Plan ("IRP") process also provides the Commission with a proceeding to review the cost of TEP's overall resource portfolio, including the costs of compliance with existing and proposed environmental regulations (Ibid).

Q. PLEASE DISCUSS HOW THE PROPOSED ECA COMPARES TO THE APS'S RECENTLY APPROVED ENVIRONMENTAL IMPROVEMENT SURCHARGE?

A. In Docket No. E-03145A-11-0224, the APS was allowed to revise its existing Environmental Improvement Surcharge to collect costs incurred to comply with environmental regulations[9]. The Environmental Improvement Surcharge in that case was initially set to zero and was capped at $0.00016 per kWh (see Decision No. 73183 Attachment H page 3 of 5). For the APS, with 28 million megawatt hours in retail sales, the cap on the Environmental Improvement Surcharge equates to a maximum charge of $4.5 million per year.

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[9] Docket No. E-01345-11-0224, In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, Decision No. 73183, issued May, 24, 2012.

Q. PLEASE COMMENT ON THE COMPANY'S PROPOSED ECA

A. Automatic adjustment mechanisms replace the current practice of regulatory lag wherein the utility is not compensated for investments made between rate cases until rates are reset in a new rate case. Regulatory lag puts financial pressure on the utility when it needs to invest money for a new customer or to comply with an imposed mandate, but it also aligns the interests of ratepayers and shareholders in that it gives utility management a strong incentive to minimize expenditures and decrease net income. Automatic adjustment clauses, on the other hand, act to relieve the utility of fighting to keep costs down and therefore divide the interest of ratepayers and shareholders. As such, automatic adjustment clauses have generally been reserved for expenditures that are largely beyond the utility's control, such a fuel prices.

When reviewing automatic adjustments clauses such as this, there is a trade-off between the loss of financial incentive to the utility to minimize costs and the increase in financial protection being granted to the utility through automatic recovery of costs. This is true with automatic adjustments clauses for fuel and purchased power, infrastructure improvements for safety, or environmental compliance. In this case, the utility argues that the IRP process provides the Commission with a proceeding to review the cost of TEP's overall resource portfolio, including the costs of compliance with existing and proposed environmental regulations.

Q. DO YOU AGREE THAT THE CURRENT IRP PROCESS IS AN ADEQUATE VENUE FOR REVIEW OF THE COMPANY'S RESOURCE PLANNING PROCESS?

A. Not at this time. While the Commission's IRP rules are comprehensive and do require utilities to show how they are planning for the future, one must also recognize that the IRPs as filed were not formally ruled upon by the Commission. Thus, while there are many benefits to the existing IRP process, one must remember that it was not a formal process wherein the Company's IRP was thoroughly vetted with testimony, discovery, and formal approval by the Commission. As such, a utility could state its actions are justified as evidenced by the IRP, but the IRP may be flawed and not justify that action at all.

Q. IS THAT THE CASE HERE?

A. In TEP's case, a review of the 2012 IRP[10] shows some areas for concern indicating an overreliance on the IRP process that might not yield the optimum - or lowest cost - result for ratepayers. First, the Commission's IRP rules state that the utilities must address energy efficiency so as to meet Commission requirements. The TEP 2012 IRP does just that. In its IRP, TEP proposes to pursue a range of cost-effective and industry-proven programs to meet future energy efficiency ("EE") targets. The proposed EE portfolio

[10] Docket No. E-00000A-11-0113, Pursuant to A.A.C. R14-2-703, et seq., Tucson Electric Power Company filed its 2012 Integrated Resource Plan on May 2, 2012.

maintains compliance with the Arizona EE Standard (2012 IRP page 23). However, the issue of concern is that the IRP shows energy efficiency as the lowest cost resource, at a levelized cost of $60 per MWH (2012 IRP page 89), but the Company compares all of the upgrades at its coal plants against a new gas-fired combined cycle plant with a levelized cost of $88 per MWH (2012 IRP at page 322). The cost of environmental upgrades at Four Corners Station (levelized cost of $64 per MWH 2012 IRP at page 322) and the San Juan Generating Station (levelized cost of $79 per MWH -2012 IRP at page 329) are both more costly than doing energy efficiency. While it is recognized that there may not be enough energy efficiency potential to replace all of the capacity of these generating stations, TEP did not review the potential in enough detail to make that determination, even though energy efficiency is the Company's least-cost resource.

Another area of concern with an over reliance on the IRP process is that compliance with present and proposed environmental mandates is a moving target. TEP itself recognizes this in the 2012 IRP where it states

Decisions around the future of TEP's coal resources are at the center of TEP's 2012 IRP. Several of TEP's coal-fired facilities are facing complex environmental challenges that will have significant rate impacts and have the potential to force them into early retirement.

As with any planning analysis, the 2012 1RP represents a snapshot in time based on existing conditions and reasonable planning assumptions. Even after the 2012 IRP filing date, TEP anticipates that the plant participants will continue to work through the complex issues surrounding plant operating agreements, fuel contracts, land leases, transmission contracts and lease purchase options before the final resource decisions are made. As shown in Figure 1, the final decision on whether TEP continues to invest in its existing coal-fired facilities or in other replacement resources will be determined on a plant by plant basis over the course of the 12-18 months after the 2012 IRP filing. It is important to note that the final decision on whether or not TEP continues to maintain its ownership interests in Four Corners, NGS and SJGS assumes that economically viable outcomes are reached on all current negotiations between plant owners, site lessors, transmission lessors and coal suppliers. Due to TEP's small ownership percentage in several of the jointly owned coal plants and the complex nature of agreements governing these plants, the final decision to remain in any particular coal plant may ultimately be decided by forces beyond TEP's control (2012 IRP at page 18).

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[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[11] Hartranft, Michael (2012, Oct 2) San Juan power plant proposal would retire two units, state says. *Albuquerque Journal.* Retrieved from www.abqjournal.com

Q. WHAT CAN YOU CONCLUDE FROM YOUR REVIEW OF THE REASONABLENESS OF THE ECA?

A. There is a great deal of uncertainty around the timing, cost, and outcome of compliance with present and possible environmental rules that might impact the Company's generating units, especially the coal fired generating units. There are also many possibilities as to what the eventual compliance with these regulations may be, including the potential for shutting down San Juan Units 1 & 2, where the Company anticipates making its biggest investment over the next few years. Reliance on the IRP process is inadequate to address these issues as the IRP process itself could use improvement; in the last IRP, the Company itself noted that it was a "snapshot in time".

As noted above, regulatory lag aligns the interests of the utility and ratepayers so as to encourage the utility to make the least cost option available to it. There is nothing presented by the Company in this case that shows the ECA would better align the interests of ratepayers and shareholders. In fact, since the utility would know that it would be fully compensated no matter the outcome of complying with environmental regulations, there is a real risk that the ECA could result in higher costs to ratepayers rather than lower. While there may be some level of expenditures that could be supplied to the utility between rates cases such as what is granted to APS, the amount of money being requested here goes well beyond that. Based on all of the above, we do not recommend its adoption as currently proposed by the utility at this time.

POST YEST YEAR ADJUSTMENTS

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED POST TEST YEAR ADJUSTMENTS?

A. TEP has adjusted its rate base to include approximately $40 million of used and useful solar projects and other plant additions that have been, or are expected to be, placed in service between December 31, 2011 (the end of the test year) and December 31, 2012 (Hutchens Direct at page 33). These projects will be benefiting customers by the time new rates are effective.

As a general rule, the Commission does not favor post test year plant unless extraordinary circumstances are present, and then up to 12 months out[12][13]. As discussed above, by disallowing costs made between rate cases, it puts financial pressure on the utility to minimize costs. We would note that the utility has provided no evidence that extraordinary circumstances exist, but it does point out that APS was able to recover post test year plant in its last rate case. The last APS rate case was a settlement and not fully adjudicated. As such, RUCO does not support post test year plant additions other than those for the Company's solar projects. While acceptance of such plant outside of a

12 In APS the Commission allowed post test year plant for 18 months after the end of the test year but that case was a result of a settlement of all issues.
13 See Decisions 7001 and 7360.

test year is unprecedented for RUCO, RUCO does so because it recognizes the commitment the Arizona Corporation Commission and other branches of Arizona state government have made to encourage the expansion of solar power.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT FWR/PG-1

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works – For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation.

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – **Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 - Connecticut Water Company - On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 - Connecticut Light & Power Company - On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel fo the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 – UNS Gas, INC. – On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 - Arizona Public Service - On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 - United Illuminating - On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in deprecation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 - Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M

expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

Paul L. Goetz, CPA

EDUCATION

B.S, Business Administration – Siena College, Albany, NY
May 1985

SUMMARY OF PROFESSIONAL EXPERIENCE

-- Partner, Bollam, Sheedy, Torani & Co. LLP, CPAs, 2011 - Present

- Member of the Firm's *Governmental Services Group*
- Over 25 years of public accounting and financial consulting experience
- Diverse background servicing clients publicly held, privately owned, and governmental entities.

-- Managing Director, UHY Advisors, September 1985 – March 2010

-- State Department of Transportation Contract Audits:

- Arizona
- Connecticut
- New York
- Delaware
- Vermont

FIELDS OF SPECIALIZATION

-- Accounting, Auditing, and Taxation Issues for:

- Government
- Architectural and engineering firms
- Manufacturing
- Insurance
- Employee benefit plans
- Publically held entities

- Significant experience with accounting due diligence with respect to mergers and acquisitions for public and privately held entities

- Significant experience with overhead rate and cost allocations studies and methodologies in accordance with Federal Acquisition Regulations and Cost Accounting Standards

- Quality control,including, recruitment and training, retention and peer reviews.

MEMBERSHIPS/ASSOICIATIONS

-- Certified Public Accountant, New York State, May 1989
-- Dean's Advisory Council - Siena College School of Business
-- Member of the American Institute of Certified Public Accountants (AICPA)
-- New York State Society of Certified Public Accountants (NYSSCPA), May 1984
-- Albany-Colonie Chamber of Commerce

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

REDACTED SUPPLEMENTAL DIRECT TESTIMONY

OF

FRANK W. RADIGAN

AND

PAUL GOETZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

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EXECUTIVE SUMMARY

Based on our examination of additional construction program information provided by Tucson Electric power Company, we have revised our original recommendation on the appropriate level of utility plant in service that should be recovered in rates.

RUCO recommends that distribution plant in service for 2011 be reduced by $70 million, which results in a reduction in required revenue of approximately $8.4 million compared to RUCO's original recommendation of $21 million.

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAMES AND ADDRESSES.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group and my office address is 237 Schoolhouse Road, Albany, New York 12203. My name is Paul Goetz. I am a partner in the firm of Bollam, Sheedy, Torani, & CO. LLP, CPAs and my office address is 26 Computer Drive West, Albany, NY

Q. ARE YOU THE SAME FRANK RADIGAN AND PAUL GOETZ THAT PREVIOSULY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. When RUCO submitted initial testimony it stated that it continued to gather information on the Company's budget process and supporting justification for its construction program. RUCO further stated that it wanted the opportunity to revise the adjustment to plant in service when rate design testimony was filed if RUCO received acceptable supporting documentation from the Company.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, RUCO has prepared the following exhibits:

Exhibit_FWR-PG-18 Planning Memorandum on New Substations

Exhibit_FWR-PG-19 Lateral 7.5 Transformer Upgrade

Exhibit_FWR-PG-20 Drexel C-44 Reconductor

Exhibit_FWR-PG-21 Excerpt from UNS 2011 10-K Report

Exhibit_FWR-PG-22 Fitch Ratings Report on Bonus Depreciation

FINDINGS AND RECOMMENDATIONS

Q. HAVE YOU HAD THE OPPORTUNITY TO CONTINUE YOUR INVESTIGATION INTO THE REASONABLENESS OF THE COMPANY'S CONSTRUCTION PROGRAM?

A. Yes, through further information exchange the Company was able to provide additional information on the justification for many projects. After submission of initial testimony, the Company was able to provide the justification for the projects done at the generating stations since the last rate case. The work orders are reasonable and support the money expended. The Company was also able to provide one year of a complete construction budget from the time it was initially reviewed by management up to the presentation to the Board of Directors in December of 2010. Finally, the Company provided a spreadsheet summarizing the expenditures by year for each of its budget categories in sufficient detail so as to be able to tie them back to a significant number of the planning memoranda already provided. All of this material was adequate to confirm that the Company has a reasonable planning process.

That said, RUCO still believes that a reduction to rate base is appropriate to reflect the fact that the Company has had an aggressive construction program in anticipation of load that has not materialized and probably will not materialize anytime soon.

Q. PLEASE EXPLAIN WHY A REDUCTION IN RATE BASE IS APPORPRIATE

A. [BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

Q. PLEASE DISCUSS THE IMPLICATIONS OF THIS OVERCAPACITY SITUATION.

A. Building a new substation takes time; from the siting, planning and construction, it may take anywhere from 3-5 years. Transformers are sized in certain increments and cannot be changed out in tiny increments as load grows. Because of this, substations are sized to not only meet current load needs, but future load needs as well. This is also true for production plants and transmission plants. As such, substation construction results in a "step function" between available capacity and load served. In the utility business this is referred to as "lumpiness" of capacity and is generally acceptable, as it is more economic to make room for excess capacity to accommodate growth in the future. There is, however, a point where the lumpiness cannot be justified under current conditions and the regulator must ascertain how much of the cost can be allowed in rates.

Another way to look at this is how it relates to risk. Should the regulator consider the Company's request to include the overcapacity, then it is the ratepayer who bears the risk of future growth. In other words, the current ratepayers will be paying for growth that may or may not occur. It is not fair, nor reasonable, to shift the risk onto the ratepayer.

From a strict regulatory standpoint, the current ratepayer should not pay for plant that is not being used. This is a basic regulatory principle. Excess plant capacity that is not being used should not be paid for by current ratepayers. Of course, the question of whether building this much capacity was even prudent is another and separate issue.

The Company's methodology for planning new substations is to review the zoning in the area and develop an estimate of what the load would be assuming that the area was fully developed. The Company's planning assumption is that one residential customer could use up to 5 kVA of substation capacity, so a 100 MVA substation can serve 20,000 homes. When the substation was planned, the load in the area was projected to grow at an annual rate of 2 MVA per year. Even considering that subdivisions bring a large amount of load all at once, this new substation was built to accommodate many years of growth.

[BEGIN CONFIDENTIAL

END CONFIDENTIAL]. The planning memorandum for each of these substations is attached as Exhibit__FWR-PG-18

Q. IN REVIEWING THE COMPANY'S CONSTRUCTION PROGRAM, IS IT EASY TO DISCERN WHICH PROJECTS WERE DONE FOR PURELY FORECASTED LOAD GROWTH?

A. Not always; some projects are recorded for multiple reasons while others are simply placed in a separate budget category (other than "New Business") that is not typically associated with forecasts or projected growth. Also, the project descriptions do not always fully explain why the work is being done. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. The project justification memorandum is attached as Exhibit__FWR-PG-19

.

[BEGIN CONFIDENTIAL

END CONFIDENTIAL].

[BEGIN CONFIDENTIAL

END CONFIDENTIAL]. The project planning memorandum is attached as Exhibit__FWR-PG-20.

Q. COULD THE UTILITY PUT ANY OF THESE SUBSTATION PROJECTS ON HOLD WHEN CUSTOMER GROWTH WAS ANTICIPATED?

A. Yes, easily. As explained previously, the actual completion of a substation from initial planning to commercial operation can be a long process, but that does not mean the actual construction is time-consuming. A brand new substation has standardized plans and specifications with parts that can be used in almost any modern [ear substations] that the Company owns. The previously discussed Canoa Ranch substation took a matter of months to construct. As such, the construction could be delayed a year or two without any material impact on the system. For example, the Cienega substation was first contemplated to be in-service in June 2008 but was delayed until July 2010.

Q. ARE THERE ANY OTHER FACTORS YOU KNOW OF THAT WOULD INFLUENCE THE UTILITY TO ACCELERATE CONSTRUCTION?

A. Yes, provisions included in the 2010 Federal Tax Relief Act provided for a 100% bonus depreciation deduction for qualified property placed in service between 9/8/2010 and 1/1/2012. Provisions also provide for a 50% bonus deprecation deduction for property placed in service in 2012. For 2011, there were no limits on the amount of qualified property placed in service that would be eligible for the accelerated deduction. UNS (as well as other utilities throughout the United States) took advantage of the accelerated depreciation deduction in 2011 as disclosed in its Form 10-K for 2011 (See Exhibit__FWR-PG-21 Excerpt from UNS 2011 10-K).

The 100% bonus depreciation deduction effectively provides for the expensing of qualified purchases rather than recovering the cost of such assets over their respective tax lives. The use of the bonus depreciation deduction has no impact on book depreciation amounts. The benefit of utilizing the deduction is to reduce current taxes by deferring income tax payments to future years. Cash flow accelerated as tax payments are delayed. For book purposes, deferred tax liabilities are created for the tax impact of the additional tax depreciation over book depreciation. Such differences would equal out over the book depreciation lives of the respective assets. The use of the accelerated depreciation may result in

Net Operating Losses (NOLs) that can be carried forward to offset taxable income in future periods.

FitchRatings issued a special report – *Bonus Depreciation in the U.S. Utility Industry* on March 7, 2011. The report noted that the bonus depreciation would result in the "significant acceleration of cash flow" due to the deferral of cash taxes. Fitch also notes that in rate-regulated utilities, the effect of bonus depreciation is to shift regulatory revenue requirements from current years to future years. Fitch also noted that bonus depreciation is anticipated to significantly improve funds from operations (FFO) and associated credit ratios (e.g. FFO interest coverage and FFO-to-debt) for certain utility and power companies in 2011 and 2012 as a result of the associated tax deferrals. (See Exhibit__FWR-PG-22 FitchRatings Report).

As disclosed in the Unisource 10-K for 2011, the use of bonus depreciation in 2011 resulted in a no taxes paid for TEP in 2011 and the Company anticipated no taxes being paid in 2012 as well. Capital spending in 2011 was $343 million for TEP compared to $278 million for 2010 and compared to the 2007-2010 four year average of $240 million.

Q. HOW DO YOU PROPOSE TO MAKE AN ADJUSTMENT TO THE COMPANY'S PLANT IN SERVICE TO REFLECT THE OVER CAPACITY THAT YOU DISCUSSED PREVOUSLY?

A. RUCO recommends that distribution plant in service for 2011 be reduced by $70 million. This adjustment was arrived at by reducing by one-half the plant additions related to new substations and the budget categories Load Redistribution, Reliability Improvements, New Business, and Equipment Replacement Substations. It is these budget categories that contain the projects discussed above and are mostly related to forecast new load. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. This adjustment is not meant to reflect the elimination of any one substation project or any one project under the other budget categories, though a case could be made that such adjustments could be done. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. To do such adjustments, however, would take a great deal more time and would require full access to all of the Company's complete budget material (which is not available). Rather, this adjustment is meant to reflect an elimination of a portion, but not an insignificant portion, of plant additions where a material amount of money has been invested in projects designed around optimistic growth assumptions and where such investments will not be fully used and useful for a long time into the future.

Q. ARE YOU CHANGING YOUR ADJUSTMENT TO RATEBASE FROM YOUR DIRECT POSITION?

A. Yes. As explained above in direct testimony RUCO was still looking at information and would supplement the initial testimony with its rate design filing. Based on responses to Data Requests, meetings with the Company and additional analysis, RUCO is modifying its rate base adjustments to reflect the updated and new information.

Q. WHAT IS THE FINANCIAL IMPACT ON THE UTILITY FROM YOUR RECOMMNEDED ADJUSTMENT?

A. The revenue requirement impact on this case is a reduction of approximately $8.4 million (compared to our original recommendation of $21 million). The adjustments themselves will be supplemented, detailed and identified in the supplemental schedules being filed with RUCO's rate design testimony. As RUCO discussed in initial testimony, this is not a permanent financial impact to the utility because when customer growth comes back, the utility will benefit from increased revenues. [BEGIN CONFIDENTIAL

END CONFIDENTIAL]. Seen from this perspective, the Company will be made whole when its load projections come to fruition.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBITS
FWR-PG-18 THRU FWR-PG-20
CONFIDENTIAL

EXHIBIT_FWR-PG-21

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011
OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _________to _________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	**UNISOURCE ENERGY CORPORATION** (An Arizona Corporation) 88 E. Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) 88 E. Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	**Common Stock, no par value**	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Tucson Electric Power Company	**Common Stock, without par value**	**N/A**

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation Yes __X__ No____
Tucson Electric Power Company Yes _____ No__X__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation Yes _____ No__X__
Tucson Electric Power Company Yes _____ No__X__

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

UniSource Energy Corporation Yes __X__ No____
Tucson Electric Power Company Yes__X__ No____

(9) In January 2012, UniSource Energy redeemed $35 million of its convertible senior notes. Pursuant to the redemption, substantially all of the notes were converted into approximately 1 million shares of UniSource Energy Common Stock.

We have reviewed our contractual obligations and provide the following additional information:

- We do not have any provisions in any of our debt or lease agreements that would cause an event of default or cause amounts to become due and payable in the event of a credit rating downgrade.
- None of our contracts or financing arrangements contains acceleration clauses or other consequences triggered by changes in our stock price.

Dividends on Common Stock

On February 24, 2012, UniSource Energy declared a first quarter cash dividend of $0.43 per share on its common stock. The first quarter dividend, totaling approximately $16 million, will be paid March 22, 2012 to shareholders of record at the close of business March 12, 2012. The table below summarizes UniSource Energy's dividends paid in 2009 through 2011.

	2011	2010	2009
Quarterly Dividend Per Common Share	$0.42	$0.39	$0.29
Annual Dividend Per Common Share	$1.68	$1.56	$1.16
Common Stock Dividends Paid	$62 million	$57 million	$41 million

Income Tax Position

As of December 31, 2011, UniSource Energy and TEP had the following carry-forward amounts:

	UniSource Energy		TEP	
	Amount	Expiring Year	Amount	Expiring Year
	-Amounts in Millions of Dollars-			
Capital Loss	$ 8	2015	$ -	-
Federal Net Operating Loss	230	2031	212	2031
State Net Operating Loss	-	2016	13	2016
State Credits	1	2016	2	2016
AMT Credit	43	None	25	None

The 2010 Federal Tax Relief Act includes provisions that make qualified property placed into service between September 8, 2010 and January 1, 2012 eligible for 100% bonus depreciation for tax purposes. The same law makes qualified property placed in service during 2012 eligible for 50% bonus depreciation for tax purposes. This is an acceleration of tax benefits UniSource Energy otherwise would have received over 20 years. As a result of these provisions, UniSource Energy did not pay any federal income taxes for the tax year 2011 and does not expect to pay any federal income taxes for 2012.

TUCSON ELECTRIC POWER COMPANY

RESULTS OF OPERATIONS

Executive Summary

TEP's financial condition and results of operations are the principal factors affecting the financial condition and results of operations of UniSource Energy. The following discussion relates to TEP's utility operations, unless otherwise noted.

2011 Compared with 2010

TEP recorded net income of $85 million in 2011 compared with $108 million in 2010. The following factors contributed to the decrease in TEP's net income:

EXHIBIT_FWR-PG-22

Utilities, Power, & Gas
U.S.
Special Report

Bonus Depreciation in the U.S. Utility Industry

Analysts

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Bonus Depreciation: Following the Cash

For U.S. companies in the utilities sector with substantial qualifying assets entering commercial service in 2011, bonus depreciation, if elected, will result in a significant acceleration of cash flow because of associated deferrals of cash taxes. A U.S. federal economic and job stimulus bill passed in December 2010 permits taxpayers to depreciate 100% of the cost of eligible, newly installed equipment after Sept. 8, 2010 and before Jan. 1, 2012. The first-year depreciation rate will fall to 50% of the cost of equipment that enters service in 2012. For a full explanation, see the Background of Bonus Depreciation on page 3.

The effect of bonus depreciation is to shift forward cash flow by deferring tax payments to later years. Bonus depreciation increases after-tax cash flow in the year that the cost of the new equipment is taken as a tax deduction, and it decreases after-tax cash flows in later years as deferred tax liabilities are reduced and cash tax payments increased. All other things being equal, the sum of cash flows over time is unchanged, but the timing of the receipt of the cash flow is more front-loaded and lumpier with enhanced cash flow at the beginning and subsequently more tax payment outflows. This is illustrated in the Hypothetical Bonus Depreciation Example table on page 4.

Bonus depreciation is anticipated to significantly improve funds from operations (FFO) and associated credit ratios (e.g. FFO interest coverage and FFO-to-debt) for certain utility and power companies in 2011 and 2012 as a result of the associated tax deferrals. In later years, FFO credit metrics and cash flow could become pressured as deferred taxes payable become cash taxes. Fixed income investors should watch out for these potential boomerangs.

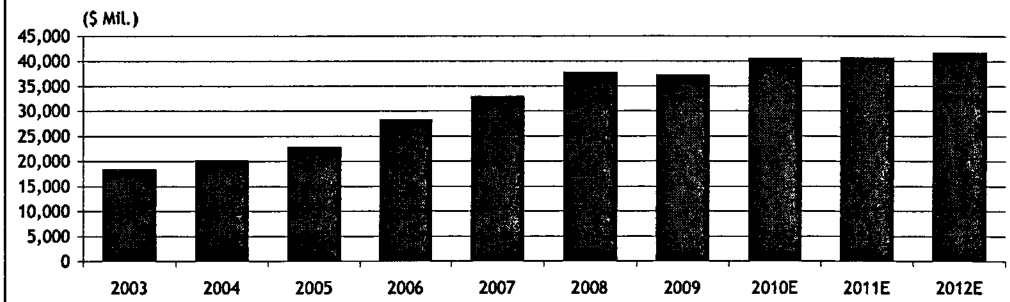
Some additional guideline credit ratios that Fitch normally reviews are based on earnings before interest, tax, depreciation, and amortization (EBITDA). EBITDA credit measures are not affected by tax filings using bonus depreciation and provide a more normalized point of view that excludes the impacts of large early cash inflow or longer term cash outflows that are associated with bonus depreciation. When Fitch compares both sets of ratios, it makes more visible the effects of various tax shelter mechanisms such as bonus depreciation, investment tax credits, and net operating loss carry-forwards and carry-backs.

Despite any concerns about increasing cash tax payments in future years, Fitch notes that there may be some offsetting favorable credit implications for companies electing bonus depreciation, depending upon the uses of the near-term cash flow from temporarily reduced tax payments. There is a small positive net present value impact of bonus depreciation for many companies. On balance, Fitch anticipates no rating upgrades as a result of the temporary improvement in FFO credit metrics that will result from bonus depreciation.

High Sector Capital Spending Produces Opportunities for Bonus Depreciation

The regulated utilities sector is one the most capital intensive sectors of the economy. Sector capital spending increased significantly in the prior decade and is anticipated to remain relatively elevated in 2011 and 2012. Much of the capital spending, including maintenance capital spending and new qualifying assets that enter service, is eligible for bonus depreciation.

35 Operating Utilities Capex Summary



E – Estimate.
Source: Fitch Ratings.

Good, Bad, or Mixed for Credit Ratings?

From a credit ratings perspective, one of the key considerations relating to bonus depreciation is how related cash is utilized. If the cash is used to reduce debt issuance, pre-fund the pension plan, or partially fund capital spending for the core business, that would be considered neutral to positive for credit. On the other hand, credit rating concerns may emerge if the cash is used disproportionately for share buybacks or other shareholder-friendly initiatives as eventually the tax bills will become due. If there were no balance sheet improvements or capital spending that produced cash flow with the bonus depreciation cash proceeds, then this may be a rating concern. Fitch analysts will track if the use of the cash is used for credit or equity friendly purposes. See Appendix 2 for a summary of 2010 issuer earnings call disclosures on bonus depreciation amounts and use of proceeds.

Analysts must also consider whether and how the utilization of bonus depreciation changes the leverage of individual issuers within a corporate group. For example, bonus depreciation at an operating subsidiary could change the timing of its individual tax payments and influence upstream dividend payment amounts. This would result in higher or lower parent debt than would otherwise be expected.

For rate-regulated utilities in many states, the effect of bonus depreciation is to shift regulatory revenue requirements and revenues from current years to later years. In certain states, calculation of regulatory rate base requires deducting deferred taxes from net utility assets. Thus, for a regulated utility facing a near-term base rate case or earnings review, the high tax deferrals associated with 100% bonus tax depreciation in the test year could reduce rate base and the related revenue requirement in a single year. Then in subsequent years, as the tax deferral is amortized, the rate base and regulated revenue requirements would gradually increase. In this case the revenue requirements are to later years. This is not a consideration for those utilities that have multi-year rate settlements in effect and are not contemplating a rate filing until 2012–2013, nor is it a consideration for companies in the power and gas sector that are not utilities and not subject to regulated tariffs.

Bonus depreciation will make it more difficult to discern a company's sequential FFO trends and to perform peer comparisons because of bonus depreciation FFO distortions. It is important that credit analysts understand the significance of bonus-deprecation-related cash flow to total cash flow; or, said another way, how much of the 2011 and 2012 total cash flow is nonrecurring and how much FFO-based credit metrics will decline when the cash inflows from bonus depreciation are no longer available and deferred taxes become payable in cash. Other tax considerations such as net operation loss (NOL) carry-forwards may also influence FFO. For issuers with NOLs, the net cash effect of bonus depreciation would extend the period of time that the issuer will benefit from an NOL position and pay less cash taxes.

Background of Bonus Depreciation

Bonus depreciation is an increasingly common form of tax relief and economic stimulus. It has been implemented several times on a national level and also in targeted geographic regions, such as to provide stimulus in the Gulf Coast region after Hurricane Katrina. The power sector has opportunities to use depreciation due to its high capital intensity. Environmental compliance and renewable mandates and investments for system growth and reliability will keep capital spending elevated

The most recent round of bonus depreciation stems from the U.S. Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (2010 Tax Relief Act) that was signed into law on Dec. 17, 2010. The Tax Relief Act provides up to 100% bonus depreciation through 2011 and reverts to 50% bonus depreciation for 2012. To be eligible for bonus deprecation under the Tax Relief Act, a qualifying asset property must be acquired or placed in service between Sept. 8, 2010 and Dec. 31, 2011 and have a useful life of 20 years or less. There remains some uncertainty regarding the particulars of bonus deprecation, which is anticipated to be clarified by IRS guidance expected to be released in March 2011. As a result, some companies' guidance on the amount of related cash flow includes wide ranges.

Prior to the Tax Relief Act, the American Recovery and Reinvestment Act of 2009 also provided for bonus depreciation. While there have been sequential rounds of tax relief via bonus depreciation over the past 10 years, Fitch recognizes the temporary nature of the incremental cash flow from this source.

Appendix 1

Hypothetical Bonus Depreciation Example

Assume that Company purchases an asset for $100 in Year 1. Further assume Company purchases another asset for $100 in Year 2. Both assets have a book life of 10 years and a tax life of five years.

The tables below show selected line items from the income statement, cash flow, and balance sheet with and without bonus depreciation. The key point is that there is no difference in the cumulative amount of cash flow over time from bonus depreciation, except for the net present value effect of tax deferrals. Cash flow is accelerated and tax payments are delayed.

Hypothetical Bonus Depreciation Example

Assume that Company purchases an asset for $100 in Year 1. Further assume Company purchases another asset for $100 in Year 2. Both assets have a book life of 10 years and a tax life of five years.

	Without Bonus								With Bonus							
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Assumptions																
Asset 1 — Put in Service	100	—	—	—	—	—	—	—	100	—	—	—	—	—	—	—
Asset 2 — Put in Service	—	100	—	—	—	—	—	—	—	100	—	—	—	—	—	—
Tax Rate (%)	35	35	35	35	35	35	35	—	35	35	35	35	35	35	3	—
Regular Tax Depreciation Asset 1[a]	(20)	(32)	(19)	(12)	(12)	(6)	—	(100)	—	—	—	—	—	—	—	—
Bonus Tax Depreciation Asset 1	—	—	—	—	—	—	—	—	(100)	—	—	—	—	—	—	(100)
Regular Tax Depreciation Asset 2[a]	—	(20)	(32)	(19)	(12)	(12)	(6)	(100)	—	—	—	—	—	—	—	—
Bonus Tax Depreciation Asset 2	—	—	—	—	—	—	—	—	—	(100)	—					(100)
Total Tax Depreciation	**(20)**	**(52)**	**(51)**	**(31)**	**(23)**	**(17)**	**(6)**	**(200)**	**(100)**	**(100)**	**—**	**—**	**—**	**—**	**—**	**(200)**
Income Statement																
Revenues	200	200	200	200	200	200	200	—	200	200	200	200	200	200	200	—
Expenses	(30)	(30)	(30)	(30)	(30)	(30)	(30)	—	(30)	(30)	(30)	(30)	(30)	(30)	(30)	—
Book Depreciation	(10)	(20)	(20)	(20)	(20)	(20)	(20)	—	(10)	(20)	(20)	(20)	(20)	(20)	(20)	—
Pretax Book Income	160	150	150	150	150	150	150	1,060	160	150	150	150	150	150	150	1060
Current (Cash) Tax Expense	(53)	(41)	(42)	(49)	(51)	(53)	(57)	(347)	(25)	(25)	(60)	(60)	(60)	(60)	(60)	(347)
Deferred Tax Expense	(4)	(11)	(11)	(4)	(1)	1	5	(25)	(32)	(28)	7	7	7	7	7	(25)
Total Tax Expense	**(56)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(371)**	**(56)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(53)**	**(371)**
Net Income	104	98	98	98	98	98	98	689	104	98	98	98	98	98	98	689
Effective Tax Rate (%)	35	35	35	35	35	35	35	—	35	35	35	35	35	35	35	—
Balance Sheet																
Cash	118	246	375	496	614	731	844	—	146	291	402	512	623	733	844	—
Asset	100	200	200	200	200	200	200	—	100	200	200	200	200	200	200	—
Accumulated Book Depreciation	(10)	(30)	(50)	(70)	(90)	(110)	(130)	—	(10)	(30)	(50)	(70)	(90)	(110)	(130)	—
Total Assets	**208**	**416**	**525**	**626**	**724**	**821**	**914**	**—**	**236**	**461**	**552**	**642**	**733**	**823**	**914**	**—**
Deferred Tax Liability	4	15	26	29	30	29	25	—	32	60	53	46	39	32	25	—
APIC	100	200	200	200	200	200	200	—	100	200	200	200	200	200	200	—
Retained Earnings	104	202	299	397	494	592	689	—	104	202	299	397	494	592	689	—
Total Liabilities and Equity	**208**	**416**	**525**	**626**	**724**	**821**	**914**	**—**	**236**	**461**	**552**	**642**	**733**	**823**	**914**	**—**
Cash Flows — Indirect Method																
Net Income	104	98	98	98	98	98	98	689	104	98	98	98	98	98	98	689
Remove Non-Cash Items:																
Book Depreciation	10	20	20	20	20	20	20	130	10	20	20	20	20	20	20	130
Deferred Taxes	4	11	11	4	1	(1)	(5)	25	32	28	(7)	(7)	(7)	(7)	(7)	25
Total Cash Flows	**118**	**129**	**128**	**121**	**119**	**117**	**113**	**844**	**146**	**146**	**111**	**111**	**111**	**111**	**111**	**844**
Cash Flow Difference Bonus Case vs. No Bonus Case								28	17	(18)	(11)	(8)	(6)	(2)	0	—
Difference in Current (Cash) Tax Bonus Case vs. No Bonus Case								28	17	(18)	(11)	(8)	(6)	(2)	0	—
Unexplained Difference								—	—	—	—	—	(0)	(0)	—	—

[a]Based on five-year MACRS (modified accelerated cost recovery system).
Source: Fitch Ratings.

Appendix 2

Examples of Company Disclosures from 2010 Earnings Calls

Issuer/(IDR, Outlook)	Estimated Amount	Use of Cash Proceeds	Other Comments
Alliant Energy Corp. (Not Rated)	Not disclosed.	Not disclosed.	Due to bonus depreciation and mixed service cost, no material federal cash tax payments expected through 2015.
American Electric Power Co. (BBB, Stable)	$1.2 billion between 2011 and 2013.	Invest proceeds in growth capex, reduce need for debt financing, fund pension and lawsuit settlement payment.	—
Black Hills Corp. (BBB, Stable)	Not disclosed.	Not disclosed.	Due to bonus depreciation, BKH accelerated $40 million of capex from 2011 into 2010. Fitch assumes significant bonus depreciation benefit given $500 million of spending for two generation projects to be in service by year-end 2011.
Centerpoint Energy, Inc. (BBB–, Stable)	Up to $500 million in 2011 and more than $50 million in 2012.	Fund capital expenditure program.	—
CMS Energy (BB+, Stable)	Not disclosed.	Not disclosed.	NOLs at the parent are significant source of tax reduction. Bonus depreciation will extend the life of NOLs.
Dominion Resources, Inc. (BBB+, Stable)	$1.6 billion–$2.5 billion between 2011 and 2013.	Share buyback $400 million–$700 million in 2011; reduce need for debt issuance in 2012.	—
DTE Energy Corp. (BBB, Stable)	$100 million–$200 million over 2011–2012.	No equity funding needs in 2011.	—
Entergy Corp (Not Rated)	$500 million over several years.	Not disclosed.	NOLs at the parent are significant source of tax reduction. Bonus depreciation will extend the life of NOLs. Some offsetting reduction in rate base and regulated revenue requirements is expected.
Exelon Corp (BBB+, Stable)	$850 million in 2011; $170 million in 2012.	Pension funding.	—
FirstEnergy Corp. (BBB, Negative)	Up to $500 million through 2012.	Retain cash; reduce need to issue debt.	—
Hawaiian Electric (Not Rated)	$55 million in 2011 and $30 million in 2012.	Not disclosed.	Awaiting rules on definition of eligible property.
Northeast Utilities (BBB, RWP)	$250 million in 2011 and in aggregate $450 million–$550 million from 2011 through 2013.	Reduce debt.	Reduce interest expense by $5 million in 2011, partially offset by $2 million reduction in earnings due to reduced rate base and lower regulatory revenue requirements.
PEPCO Holdings (BBB, Stable)	No impact until later years due to NOL position.	Not disclosed.	The cash flow benefit from bonus depreciation will be delayed until after NOLs are used. Some offsetting reduction in rate base and revenue requirements may occur in later years, but not immediately in 2011–2012 due to use of NOLs.
PPL Corp. (BBB, Stable)	$700 million between Sept. 9, 2010 and end of 2012.	Eliminate need for equity funding until end of 2011 at the earliest.	Adverse effect on EPS.
SCANA Corp (BBB+, Stable)	$50 million in 2011. (Note: New nuclear investment will not be eligible for bonus depreciation, since it will not enter service in the relevant years.)	Mitigate external funding needs.	Utility will experience reduced rate base due to netting of deferred taxes. Not likely to affect rates charged to consumers, but it is incorporated in quarterly monitoring reports provided to South Carolina regulators.
Sempra Energy (A–, Negative)	Not disclosed.	Not disclosed.	As a result of bonus depreciation and other factors, SRE will not be paying any cash federal taxes for several years. The utilities will have a small reduction in earnings (example given in the area of $25 million–$40 million annually), but it is minor relative to the cash flow effects.
Southern Co. (A/Stable)	$500 million–$600 million in 2011; $250 million–$300 million in 2012.	Reduce external debt and equity funding needs in 2011–2012.	—
TECO Energy Inc. (BBB–, RWP)	$200 million tax benefit from 2008 through 2012.	Use the incremental cash flow in the utility.	Extends the period in which TECO will not pay any cash taxes on a consolidated basis due to NOL position.
Westar Energy, Inc. (BBB–, Positive)	Not likely to use bonus depreciation to the extent that it would eliminate use of other more permanent forms of tax incentives.	Not relevant.	—
Wisconsin Energy Co. (A–, Stable)	$100 million in 2011; $200 million in 2012.	Increase dividend payout.	Some offsetting reduction in regulated revenues is expected.

NOL – Net operation loss.
Source: CallStreet earnings call transcripts, Fitch.

EXHIBIT
RUCO-6
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 21, 2012

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EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP" or "Company") is a Class A public utility and is a wholly owned operating subsidiary of UNS Energy Corporation. TEP is an electric utility serving approximately 404,000 retail customers in the Tucson metropolitan area of Pima County as well as parts of Cochise County. TEP also sells electricity to other utilities and power marketing entities in the western United States.

On July 2, 2012, the Company filed a general rate application requesting a revenue increase of $127.8 million or approximately a 15.3 percent increase over test year adjusted revenues of $837 million. The average residential customer would see their monthly bill increase from $85.17 to $95.82, a monthly increase of $10.65. RUCO is recommending a revenue increase of $26.8 million, an increase of 3.1 percent over test year revenues.

The Company is also proposing an Original Cost Rate Base (OCRB) of $1,519,073 and a Rate of Return of 8.52% while RUCO is proposing an OCRB of $1,237,469 and a Rate of Return of 7.28%.

In addition to an increase in rates for all classes of TEP's customers the Company is also requesting modifications to its Purchase Power and Fuel Adjustment Clause (PPFAC) and a modified approach to funding the cost of its energy efficiency (EE) and demand side management (DSM) programs. The Company is also seeking to establish a lost fixed cost recovery program related to energy efficiency and renewable generation requirements and an environmental cost recovery mechanism.

INTRODUCTION

Q. Please state your name, position, employer and address.

A. My name is Robert B. Mease. I am Associate Chief of Accounting and Rates employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant and currently licensed in the state of West Virginia. My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding TEP's application for determination of the current fair value of its utility plant and property and for a permanent increase in its rates and charges passed on to ratepayers for utility services.

Q. Please describe your work effort on this project.

A. I reviewed financial data provided to me by the Company and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the overall revenue requirement for the Company and future rate design that the Company is proposing. My recommendations are based on these analysis. Procedures performed include the in-house formulation and analysis of this data, the review and analysis of the Company's responses to RUCO's data requests, a review of data responses to the Commission Staff as well as other intervening parties, and a review of prior ACC dockets related to TEP filings. I also made on-site visits to TEP's Headquarters and Sundt generating plants both located in Tucson, AZ, and San Juan generating plants, Nos. 1 and 2, located in Farmington, NM with Mr. Frank Radigan. Mr. Radigan is serving as RUCO's consultant in the case and worked in conjunction with RUCO's staff.

Q. Can you please identify the exhibits that you are sponsoring?

A. Yes, I am sponsoring schedules RBM -1 through and including RBM – 21.

Q. Please summarize the adjustments to rate base and operating income issues addressed in your testimony.

A. My testimony addresses the following issues:

RATE BASE ADJUSTMENT SUMMARY

Rate Base Adjustment No. 1 – Gross Utility Plant in Service

RUCO is recommending reduction of Gross Utility Plant in Service by $230,152,657 as explained in the direct testimony of RUCO consultant, Frank Radigan.

Rate Base Adjustment No. 2 – Accumulated Depreciation

As explained in the direct testimony of RUCO consultant, Frank Radigan, RUCO is recommending reducing the Accumulated Depreciation Account by $133,708,325.

Rate Base Adjustment No. 3 – Accumulated Deferred Income Taxes (ADIT)

RUCO has removed TEP's inclusion of Net Operating Loss (NOL) in ADIT, $67,051,372 based on the belief that the inclusion of the Deferred Tax Asset resulting from the 2011 NOL is not correct and the Company's inclusion in rate base does not conform to the position the Commission has taken in the past.

Rate Base Adjustment No. 4 – Regulatory Liability

RUCO is recommending that the Company establish a Regulatory Liability of $102,784,786 for the excess depreciation that should be returned to the ratepayers.

Rate Base Adjustment No. 5 – Regulatory Asset (Nogales Transmission Line)

RUCO has been advised that the Company will seek recovery for the sunk costs, $11,088,732, related to this project at FERC prior to making application before this Commission.

Rate Base Adjustment No. 6 – Allowance For Working Capital

Cash Working Capital should be decreased by $4,266,000 based on adjustments to various operating expense accounts.

OPERATING INCOME ADJUSTMENT SUMMARY

Operating Income Adjustment No. 1 – Other Operating Income (Springerville Units 3 and 4 - Rental Income)

The Company's proposal for splitting $6,931,002 income received from the rental of coal handing equipment and common facilities is not in the best interest TEP ratepayers. The income is related to rental activities generated from Springerville Units 1 and 2 and should be included in other operating revenue. Accordingly, RUCO has reversed TEP's adjustment.

<u>Operating Income Adjustment No. 2. – Depreciation Expense</u>

RUCO is recommending a reduction in test year depreciation expense by $26,365,701. RUCO consultant Frank Radigan will provide testimony on this adjustment.

<u>Operating Income Adjustment No. 3 – Payroll Expense</u>

RUCO does not agree with the methodology used by the Company in calculating test year payroll expense adjustment and proposes a reduction in test year expense of $1,470,721.

<u>Operating Income Adjustment No. 4– Incentive Compensation Adjustment</u>

RUCO believes that <u>all</u> incentives paid to employees should be split between the shareholders and ratepayers. The proposed adjustment reduces operating expenses by $2,530,620.

<u>Operating Income Adjustment No. 5 – Payroll Tax Expense Adjustment</u>

RUCO is recommending a reduction in payroll tax expense of $272,631 resulting from the proposed reduction of payroll expenses and incentive adjustments.

Operating Income Adjustment No. 6 – Amortization Nogales Line

RUCO is proposing eliminating the total test year adjustment of $2,982,638 related to amortization of the Nogales Transmission Line (See Rate Base Adjustment No. 5, and Operating Expense Adjustment No. 2)

Operating Income Adjustment No. 7 – Overhauls and Outage

Overhaul and Outage Expenses is calculated incorrectly by the Company and RUCO is taking exception. RUCO is proposing an adjustment to test year income by $4,883,016.

Operating Income Adjustment No. 8 – INTENTIONALLY LEFT BLANK

Operating Income Adjustment No. 9 – Officers and Directors Insurance

RUCO believes that officers and directors insurance expense should be the responsibility of the shareholder as well as the ratepayer and should be shared equally. RUCO's proposal reduces the Company's operating income by $289,320.

Operating Income Adjustment No. 10 – Lime Expense

RUCO is proposing that the Company's test year adjustment to the lime expense account be reduced by $149,998.

Operating Income Adjustment No. 11 – Rate Case Expense

The Company's request for the recovery of rate case expense is excessive and should not be borne entirely by TEP's ratepayers. RUCO is proposing the Company rate case expense of $500,000 be approved by the Commission.

Operating Income Adjustment No. 12 – Miscellaneous and General Expense

RUCO is proposing to eliminate Company contributions of $2,139,016 from test year results.

Operating Income Adjustment No. 13 – Property Tax Expense

An adjustment to property tax expense, of $3,110,547 is being proposed by RUCO due to the proposed reduction in the Company's rate base.

Operating Income Adjustment No. 14 – Income Tax Adjustment

RUCO is proposing that current year's income tax expense be increased by $22,535,476.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and identify RUCO's recommended revenue increase, operating income requirement as well as the Company's Original Cost Rate Base (OCRB) and Fair Value Rate Base (FVRB).

A. RUCO is recommending a revenue increase as follows:

000's	TEP	RUCO	DIFF.
Increase in gross revenue	$127,765	$ 26,781	($100,984)
Increase in revenues required	15.27%	3.07%	(12.20%)

RUCO is recommending operating income levels as follows:

000's	TEP	RUCO	DIFF.
Required operating income	$129,484	$97,612	($ 31,872)

RUCO is recommending OCRB and FVRB as follows:

000's	TEP	RUCO	DIFF.
Original Cost Rate Base	$1,519,073	$1,237,439	($ 281,634)
Fair Value Rate Base	$2,280,216	$1,910,221	($ 369,996)

RATE BASE

Q. Can you please explain your determination of the FVRB as shown on Schedule RBM-1?

A. RUCO's determination of the FVRB consists of three elements. First, the value of the OCRB was restated to reflect RUCO's adjustments to the rate base determinants. Second, the value of RCND (Reconstruction Cost New less Depreciation) was computed by multiplying RUCO's adjusted OCRB by the ratio of the Company's OCRB to its RCND as filed. Third, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RUCO's re-computed RCND.

Q. Can you elaborate on the adjustments RUCO is proposing to the OCRB?

A. Yes. I will describe each of the adjustments that RUCO is recommending to the OCRB as filed by the Company.

Rate Base Adjustment No. 1 – Gross Utility Plant in Service

Q. Can you please explain RUCO's proposed adjustment to Gross Utility Plant in Service?

A. RUCO is recommending reduction of Gross Utility Plant in Service by $230,152,657 based on the recommendation of RUCO consultant Frank Radigan.

Rate Base Adjustment No. 2 – Accumulated Depreciation

Q. What adjustments has RUCO recommended to the Company's Accumulation Depreciation accounts?

A. Based on the recommendation of RUCO consultant, Frank Radigan, RUCO is recommending reducing the Accumulated Depreciation Account by $133,708,325.

Rate Base Adjustment No. 3 – Accumulated Deferred Income Taxes (ADIT)

Q. Does RUCO take exception to any items included as a deferred tax asset or liability?

A. Yes. RUCO does not believe that the inclusion of the Deferred Tax Asset related to the 2011 Net Operating Loss (NOL) is appropriate and the Company's inclusion in rate base does not conform to the position the Commission has taken in the past. Simply stated, the Company has made a voluntary election to take "bonus depreciation" which benefits the company but not the ratepayer, and will result in higher rates that the ratepayer would otherwise not have to pay.

Q. Can you identify those instances where the Commission has not allowed the inclusion of NOL's in the Company's filings?

A. There are two cases noted, Las Quintas Serenas Water Company, Decision No. 72498, and Rio Rico Utilities, Inc., Decision No. 72059. In both cases the Commission's decision did not allow for the inclusion of the Deferred Tax Asset created by the NOL, to be included in the calculation of the Company's rate base.

Q. Can you identify the Company's NOL carryforward from year 2011 and what is the impact on the Deferred Tax Asset account?

A. The Company's NOL carryforward for year 2011 was $231,860,076.[1] The impact on the ADIT accounts as described by the Company:

FED & NM NOL Carryforward (Federal and New Mexico)	$ 82,071,149
AZ NOL Carryforward	1,256,587
Post Test Year Plant NOL	3,161,209
Delayed Plant Adj. NOL	2,722,576
TOTAL TEP	$ 89,211,521

(ACC Jurisdictional $67,051,372)

Q. Can you explain how the NOL has an effect on rate base?

A. Yes. I will give an example using the FED & NM NOL Carry forward as the basis for my calculation:

NOL Carryforward Year 2011		$231,860,076
Federal Tax Rate	35.000000 %	
NM Tax Rate	0.396844%	
Sum of both Tax Rates		35.396844
NOL Included in Rate Base (ADIT)		$ 82,071,149

(ACC Jurisdictional $61,684,675)

[1] See Company's response to RUCO Data Request No. 3.09

The ADIT increases the total rate base as it is recorded on the Company balance sheet as an asset.

Q. What is the primary reason for the Company's NOL for year 2011?

A. The Company has taken advantage of "Bonus Depreciation" for years 2008 and maximized in year 2011. In general, for the years 2008, 2009, and 2010 (through September 8, 2010) bonus depreciation of 50 percent of the cost of qualifying assets placed in service was allowed as a tax deduction to arrive at taxable income. Qualifying assets placed in service after September 8, 2010 and continuing through 2011, one hundred percent of the cost was allowed as a tax deduction.

Q. What is the purpose in creating such tax benefits?

A. Whenever governmental legislation permits such "write-offs" for business it is believed that additional investments will be made by businesses for the benefit of stimulating the economy. By allowing accelerated depreciation deductions additional cash is provided for further investment or providing additional employment opportunities. The most recent governmental legislation was entitled Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. This bill provided for 100 percent bonus depreciation for qualified property placed in service after September 8, 2010 and before January 1, 2012.

Q. Are company's required to record bonus depreciation if investments are made in qualifying assets?

A. No. Companies can elect to take bonus depreciation or not take the bonus depreciation.

Q. What was the Company's total NOL attributable to bonus depreciation?

A. Of the Company's total NOL of $231,860,076 for year 2011, $243,092,468 was directly attributable to bonus depreciation.[2]

Q. What are the Company's options related to NOL's?

A. NOL's can be carried back two years in order to recover prior year's tax payments and/or carried forward for a maximum of twenty years or until the NOL is utilized. TEP has indicated[3] that they will carryforward the total NOL to future years.

Rate Base Adjustment No. 4 – Regulatory Liability

Q. Does the Company have any existing regulatory liabilities?

A. No. As of the end of the test year the Company had no regulatory liabilities recorded on their financial statements.

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[2] See Company response to RUCO Data Request No. 3.09
[3] See Company response to RUCO Data Request No. 3.12

Q. Is RUCO recommending the establishment of a Regulatory Liability?

A. Based on the recommendation of RUCO witness Frank Radigan, RUCO is recommending that the Company establish a Regulatory Liability for the excess depreciation that should be returned to the ratepayers. The net adjustment to the liability account is $102,785,000. (The total excess depreciation that should be returned to ratepayers is $123,342,000 less depreciation returned to ratepayers for this test year of $20,557,000).

Q. Can you explain why RUCO believes that there is excess depreciation and why any excess depreciation should be paid back to ratepayers?

A. A complete explanation of this adjustment is included in the testimony of Mr. Radigan.

<u>Rate Base Adjustment No. 5 – Regulatory Assets (Sahuarita Nogales Transmission Line Project)</u>

Q. Can you please explain the project identified as the Sahurarita Nogales Transmission Line?

A. TEP began to consider a transmission link to Mexico after participating in the "United States – Mexico Electricity Trade Study" in 1991. The study identified potential economic and technical benefits from increased trade and cooperation between U.S. and Mexican utilities and expressed hope that the report would prompt utilities to begin studying specific projects.[4] In 2000, TEP entered into a memorandum of understanding with Citizens Utilities, the City of Nogales electricity provider, to work together to design, site, permit, and build what would ultimately become known as the Sahuarita-Nogales 345-kV Transmission Line Project.

Between October 2000 and March 2005, TEP incurred expenses of $11,088,732 related to this project. The costs include expenses for line siting, engineering, consulting and other costs necessary to get the project to the construction phase of $8,947,914 and $2,140,818 related to the acquisition of land and land rights.

Q. Why did the project never materialize?

A. The Commission approved the construction route along the "western" corridor in 2002 but before the construction began the Department of Energy in March of 2005 released a final decision that indicated the "central" corridor was preferred by the U.S. Forest Service. Because the "central" corridor conflicted with the Commission's decision, TEP was left without authorization to build along a single route. In addition, additional improvements have been made to existing transmission systems and the 345-kV transmission line is no longer needed.

[4] See Mr. DeConcini's testimony pages 38 thorough 40.

Q. What has the Company proposed related to the costs incurred to date?

A. TEP is proposing an adjustment to recover costs not invested in tangible assets, land and land rights. In summary, TEP is requesting to amortize $2,982,638 ($8,947,914 / 3) for three years and has made a test year adjustment to recognize this expense.

Q. Can you please explain RUCO's proposed adjustment to the Sahuarita Nogales Transmission Line Project?

A. RUCO does not believe that the costs of this project should be charged to TEP utility ratepayers as they have not benefited from these expenditures. RUCO therefore is proposing that the amortization expense of $2,982,638 be removed as a test year operating expense adjustment and the total cost of the project, $11,088,732, which includes both the land and land rights, be removed from rate base.

Q. Has RUCO learned that the Company's request may be withdrawn? And if so, what is RUCO's position?

A. Yes, RUCO understands that the Company has withdrawn its request for the time being and will seek relief before the FERC. Depending on the decision made by FERC the Company may later renew its request before the Commission. RUCO does not object to this option.

Rate Base Adjustment No. 6 – Cash Working Capital

Q. Please explain RUCO's adjustment to Cash Working Capital.

A. RUCO is recommending a Cash Working Capital decrease of $4,266,000. The adjustment is the result of RUCO's proposed expense reductions.

OPERATING INCOME

Q. Is RUCO recommending changes to the Company's proposed test year operating revenues and expenses?

A. Yes. The Company proposed numerous adjustments to its historical test year operating income. RUCO analyzed the Company's adjustments and proposed several changes. In addition, RUCO is recommending additional adjustments based on data requests provided by TEP. RUCO's adjustments to operating income are explained as follows.

Operating Income Adjustment No. 1 – Other Operating Income (Springerville Units 3 and 4 - Rental Income)

Q. Can you please explain the source of the rental income received from the Springerville Units 3 and 4 and the Company's proposal for reporting the rental income?

A. The owners of Springerville Units 3 and 4 pay TEP a monthly fee as compensation for use of the fuel handling facilities ($630,833) and common facilities ($529,334) that previously served only the Springerville Units 1 and 2. TEP has proposed that only 50 percent of the rental income, (\$630,833 + \$529,334) X 12) = \$13,933,004 / 2 = \$6,961,002, be shared with ratepayers in the proposed cost of service.[5]

Q. What is the Company's justification for recognizing only 50 percent of this income in TEP's proposed revenue requirements?

A. The Company has indicated several reasons that sharing of this revenue is appropriate. First, the initial development of Springerville Units 3 and 4 was managed by TEP's sister Company, UniSource Energy Development Company (UED). Over a three year period, UED invested approximately \$32.8 million in development costs that were borne by the shareholders of UNS Energy. Development rights to Units 3 and 4 were ultimately transferred to Tri-State Generating and Transmission Association ("Tri-State") and Salt River Project ("SRP") respectively, and both units are now complete and operating. Second, the Company has estimated savings totaling approximately \$21 million in the Company's test-year revenue requirements resulting from spreading O&M and administrative costs as well as property tax expenses over four units instead of just two units.

Q. Despite the Company's explanation for sharing of the rental revenue is RUCO recommending an adjustment?

A. Yes. RUCO proposes that the full amount of \$13,933,004 represents rental revenues that should remain in the test year for the benefit of

[5] See Company response to RUCO Data Request 8.04

ratepayers. First, while RUCO understands that the initial investment may have been the risk of a sister Company this reasoning does not support ratepayers having to pay higher rates. Second, TEP has identified approximately $21 million in savings as a result of sharing costs between four units as opposed to two units. TEP should continuously be looking for such savings particularly during periods of slow growth and increasing costs. The Company stated in its testimony that operating expenses continue to increase and that cost control measures are constantly being initiated. Reducing operating expenses, while maintaining a safe and reliable system, are a normal and continuing business objective and does not provide justification for the sharing of expenses or revenues. Recognizing the total revenues generated from these facilities, should be for the benefit of the ratepayers and not shared with Company shareholders.

Operating Income Adjustment No. 2. – Depreciation Expense

Q. Can you please explain your adjustment to depreciation expense?

A. RUCO is recommending a reduction in test year depreciation expense by $26,365,701 as explained by Mr. Radigan in his testimony.

Operating Income Adjustment No. 3 – Payroll Expense

Q. Did TEP make test year adjustments related to payroll increases?

A. Yes. TEP calculated payroll increases and included a test year adjustment.

Q. Does RUCO agree with the calculation and can you explain the methodology used by TEP in calculating wage increases?

A. No. RUCO does not agree with the method used. The Company took the average Operation and Maintenance total wages for years 2010 and 2011, and then calculated a 3 percent increase for years 2012 and 2013. The total calculated increase for both years 2012 and 2013 were then included as a test year adjustment. RUCO takes the position that including a second year of anticipated increases is too far removed from the test year to be included as an adjustment and is recommending that the calculated increase for year 2013, $1,470,721, be removed from test year adjustments.

Operating Income Adjustment No. 4 – Incentive Adjustment

Q. Can you please explain operating income adjustment 4?

A. RUCO believes that all incentives paid to employees should be split between the shareholders and ratepayers. TEP excluded 50 percent of the incentive payment made to officers but maintained 100 percent of payments to all other employees. The Commission's normal practice is to approve the sharing of incentive payments between shareholders and ratepayers has been accepted. (See UNS Gas, Inc. Decision No. 70011, UNS Electric Decision No. 70011 and Southwest Gas Decision No. 70665) In addition, there is no assurance that incentive payments included as a test year adjustment will be paid out in future years as they are based on performance.

Q **Can you identify incentive plans available to employees of TEP?**

A. All TEP non-union employees, including officers, participate in UNS's short –term incentive Performance Enhancement Plan (PEP) which is tied to annual compensation. The structure determines eligibility for certain bonus levels by measuring UNS's performance as it impacts investors, customers, community/environment and employees.

Q. **Has the Company included long term incentive plan payments in the test year adjustments?**

A. No. The Company has not included long term incentive plan payments as an adjustment.

Q. **What is RUCO proposing as a test year adjustment for incentive payments?**

A. RUCO is proposing a reduction in the Company's post-test year adjustment for incentive payments of $2,530,620.

Operating Income Adjustment No. 5 – Payroll Tax Expense Adjustment

Q. Why is RUCO making an adjustment for payroll tax expenses?

A. RUCO is recommending a reduction in payroll tax expense of $272,631 resulting from the proposed reduction of payroll expenses, $82,835, and incentive adjustments $189,796.

Q. Is RUCO recommending any other adjustments to payroll tax expenses?

A. No.

Operating Income Adjustment No. 6 – Amortization Nogales Line

Q. Can you please explain your adjustment to amortization?

A. RUCO is proposing eliminating the test year adjustment for amortization of the Nogales Transmission Line. RUCO does not believe that the ratepayers should be responsible for potential write-off as they have received no benefit from this expenditure. (See Rate Base Adjustment No. 5 and Operating income Adjustment No. 2)

Operating Income Adjustment No. 7 – Overhauls and Outage

Q. Is RUCO recommending a reduction to the Company's post-test year adjustment to Overhaul and Outage Expense?

A. Yes. RUCO is proposing a reduction to test year expense by $4,833,016.

Q. How did the Company calculate their test year adjustment to this expense?

A. TEP computed an estimated annual cost based on budgeted amounts for years 2012 through and including 2018, for each plant. The budgeted cost for each type of overhaul, major and minor was then applied to the frequency for each plant where a major or minor overhaul was going to occur. The calculated average was then applied to each plant location to arrive at the Company's total test year adjustment.

Q. Why does RUCO oppose the method used by the Company?

A. First, estimating costs to year 2018, does not comply with sound rate making principles. Second, calculating seven years of future costs does not represent an accurate known and measurable adjustment. Including seven years of average costs would overstate the test year adjustment significantly.

Q. Would you please explain how RUCO arrived at its proposed adjustment?

A. The Company provided all details for their adjustment to this expense. The schedule identified the year, 2012 through 2018, the location, and budgeted costs broken down into both major and minor overhauls. The Company estimated 2012 budgeted cost is $9,825,000. RUCO included the estimated 2012 costs as a known and measurable change and reduced the test year adjustment accordingly.

<u>Operating Income Adjustment No. 8 – Intentionally Left Blank</u>

<u>Operating Income Adjustment No. 9 – Officers and Directors Insurance</u>

Q. Can you please explain RUCO's adjustment to Officers and Directors Insurance Expense?

A. RUCO believes that Officers & Directors Liability Insurance expense is the type of expense that should be shared equally between ratepayers and shareholders. RUCO has reduced test year ACC Jurisdictional operating expenses by $289,320 representing a 50/50 split between the shareholder and the ratepayer.

Q. Why does RUCO believe this expense should be equally shared?

A. Officers & Directors Liability Insurance primarily is for the purpose of protecting officers and directors from potential lawsuits. In many cases these lawsuits are from irate shareholders. Benefits paid out under this insurance coverage provides cash available to shareholders that would have been paid by the Company had the Company not had in place such liability insurance coverage. It also provides the Company with the ability to attract and retain qualified directors and officers as they are relieved from personal liability when making decisions on behalf of the Company.

Q. Has the ACC approved a 50/50 sharing of Director's & Officers (D&O) Insurance expense in past rate case filings?

A. The adjustment representing a 50/50 sharing of D&O insurance was proposed in the Southwest Gas Corporation most recent rate case in Docket No. G-01151A-10-0458. This case resulted in settlement, Decision No. 72723, and incorporated the proposed sharing of the D&O expense on a 50/50 percent basis.

<u>Operating Income Adjustment No. 10 – Lime Expense</u>

Q. Would you please explain the adjustment to this expense account?

A. Yes. TEP, when filing their initial rate application, under-estimated "sulfur credits" used as an offset to monthly lime costs. The Company originally estimated sulfur credits through the month of April, 2012, and then annualized these four months as a basis for the test year adjustment. The monthly sulfur credits have since been updated through September, 2012, and based on the addition of an additional five months the annualized sulfur credits have increased. RUCO is proposing a reduction in the Company's test year adjustment to lime expense by $149,998 as a result of including the additional five months of credits.

Operating Income Adjustment No. 11 – Rate Case Expense

Q. Please explain your adjustment to Rate Case Expense.

A. The Company has proposed recovery of $1,415,000 for rate case expenses for outside services and requests to amortize this expense over a three year period. RUCO believes the Company's proposed rate case expense is excessive, and should be reduced significantly, when compared with rate case expense in prior rate case submissions that have been approved by the Commission. RUCO proposes that the rate case expense should be amortized over a four year period, as the Company is currently doing, rather than the three year proposed period.

Q. Has RUCO proposed an adjustment to TEP's level of rate case expense to be recovered from ratepayers?

A. Yes. RUCO proposes a more appropriate level of rate case expense of $500,000 given that this case is more involved than the other cases that RUCO has reviewed. By comparison, RUCO believes $500,000 in rate case expense is reasonable under the circumstances of this case. RUCO further proposes that the amortization period be over a four year period, $125,000, as was authorized during the last rate case.

Q. How did RUCO arrive at its adjustment to rate case expense?

A. RUCO compared the Company's proposed level of rate case expense to rate case expens e that was approved in other rate cases before the

Commission. Based on this review, RUCO believes that the Company's request is not reasonable in this case and should be reduced to a more appropriate level.

Q. What other cases did RUCO review?

A. RUCO reviewed the last three UNS Gas cases (Decision Nos. 73142, 71623 and 70011). The amount approved by the Commission were $400,000, $300,000 and $300,000 respectively. Also, in the most recent UNS Electric rate case filing the Commission approved rate case expense recovery of $276,000. (Decision No. 70360)

<u>Operating Income Adjustment No. 12 –Miscellaneous and General Expenses</u>

Q. Can you please describe RUCO's adjustment for charitable contributions made by the Company?

A. Yes. RUCO believes it is extremely important for TEP to be a good corporate citizen and contribute to local community activities and charities. However, RUCO does not believe that contributions to charitable activities constitute an expense that should be passed on to ratepayers. The total reduction in test year operating income for charitable contribution is $39,016.

A second adjustment to this account relates to the reduction of operating expenses, $2,100,000, for the new office building. RUCO is recommending that the operating expenses of the facility be eliminated from expenses as RUCO is recommending that the building be removed from rate base as well as the operating expenses. (See FWR testimony)

Operating Income Adjustment No. 13 – Property Tax Expense

Q. Does RUCO accept the Company's methodology in calculating property tax expense?

A. Yes. The method used by the TEP in this rate case is consistent with prior cases as filed and has been accepted by RUCO.

Q. Why is RUCO making an adjustment to the Company's property taxes as filed?

A. RUCO is proposing a reduction in gross plant in service by $230,152,657, as discussed in Rate Base Adjustment No. 1. As a consequence of excluding plant from rate base the property taxes associated with the proposed reduction in plant is also reduced. The reduction in allowable property taxes based on the recalculated expense is $3,110,547.

Operating Income Adjustment No. 14 – Income Tax Expense

Q. Has RUCO made an adjustment to Income Tax Expense as filed by the Company?

A. Yes. RUCO has adjusted this expense based upon the methodology that is used in all rate applications reviewed by RUCO.

Q. Can you explain the method utilized in calculating income tax expense both for the test year adjustment as well as the method used in calculating the tax effects of proposed revenue adjustments?

A. When calculating income tax expense for rate making purposes RUCO begins with operating income before taxes and from that amount will deduct Arizona income taxes due and interest synchronization. (Interest synchronization is calculated as follows: Adjusted ACC Jurisdictional Rate Base X Weighted Cost of Debt) The two results, Arizona income taxes and interest synchronization, are multiplied by the statutory Federal Income Tax Rate. In this case RUCO has used 35 percent as the statutory Federal Income Tax Rate.

Q. When applying this methodology to the RUCO's proposed test year operating income what was the result?

A. There was an additional income tax expense proposed by RUCO of $22,525,476 and added to the Company's operating expenses.

Q. Was there an adjustment to income tax expense after RUCO's final revenue requirement was determined in this rate filing?

A. Yes. The increase in income tax expense related to RUCO's additional revenue requirement is $10,622,584.

<u>Purchased Power and Fuel Adjustment Clause – ("PPFAC")</u>

Q. Does TEP currently have a PPFAC in place?

A. Yes. TEP has a PPFAC in place since the last rate case. The PPFAC was established in Decision No. 70628.

Q. Can you explain the basic concept of the PPFAC?

A. The PPFAC is a mechanism approved by the Commission that allows the Company to recover its purchased power and fuel expenses. The allowable expenses to be recovered in the PPFAC include fuel and purchased power costs incurred to provide service to retail customers as well as direct costs of contracts used for hedging the system fuel and purchased power. The specific cost components include FERC accounts: 501 - Fuel and Steam; 547 - Fuel Other Production; 555 - Purchased Power; and 565 - Wheeling - Transmission of Electricity by Others. As an offset to these costs the following are to be credited back to TEP's customers through the PPFAC: (1) short-term off-system wholesale revenue recorded in FERC account 447; (2) 10 percent of annual positive wholesale trading profits, and; (3) 50 percent of the revenues from sales of SO_2 emission allowances.

The PPFAC also established an average retail base cost of fuel and Purchased Power recovery component of $0.028896 per kWh, established forward and true up components, and established the first PPFAC year beginning April 1, 2009.

Finally, specific dates were identified for filing updates to the forward and true up components and for the PPFAC rate with all component calculations, including supporting data. TEP also has the ability to request an adjustment for the forward component at any time during the year should an extraordinary event occur. Finally, short-term wholesale sales revenue and 10 percent of annual net positive trading profits will be credited to the fuel and purchased power costs.

Q. Has the Company proposed any changes to the PPFAC in this rate application?

A. Yes. The Company is proposing to (1) eliminate the base fuel rate and recover all fuel and purchased power costs through the PPFAC; (2) develop multiple PPFAC rates to differentiate between on-peak and off-peak, winter and summer voltage levels at which customers receive service; (3) add several additional costs that would be recovered through the PPFAC. These additional costs include any credit costs and broker fees associated with power supply and procurement, lime costs incremental to the amount included in test year and recovery of future greenhouse gas costs. TEP has also proposed that 100 percent of the SO_2 sales would be credited back to ratepayers if the Commission approves the recovery of the incremental lime costs and finally, TEP has proposed alternatives filing dates that were approved by the Commission in the last rate case

Q. Does RUCO agree with including these changes being proposed by the Company?

A. No. RUCO does not agree with making changes to the PPFAC at this time for the following reasons:

<u>Additional Costs to be Included in PPFAC</u>

RUCO does not believe adding other costs to the PPFAC adjustor add value to the ratepayer at this time. Costs related to broker fees and credit expenses is immaterial (estimated at $41,000 per Company[6]) and should remain as part of O&M expenses in base rates. Incremental lime costs or greenhouse gas costs are unknown at this time and the Company cannot estimate what these costs will be. Broker fees and credit costs were not approved by the Commission in TEP's last rate case and should not be approved in this rate case.

[6] See Company response to RUCO 3.23

Eliminate the Base Fuel Rate and Recover All Fuel and Purchased Power Costs Through the PPFAC

The Commission has consistently found it in the public interest to have a portion of purchased power and fuel costs remain in base rates. Having a portion of fuel costs embedded in base rates creates an appropriate sharing of risk between both the shareholder and ratepayer. Under TEP's proposal, all risk is shifted to the ratepayer and there is no incentive to contain purchased power and fuel costs.

Q. Is TEP proposing additional adjustor mechanisms in this rate case submission?

A. Yes. The Company has proposed two new adjustor mechanisms. The first adjustor is a Lost Fixed Cost Recovery ("LFCR") mechanism and the second adjustor is an Environmental Compliance Adjustor. TEP is also proposing a new way to determine the energy efficiency program costs that will be recovered through TEP's existing DSMS.[7]

LOST FIXED COST RECOVERY MECHANISM – ("LFCR")

Q. Is TEP proposing a revenue decoupling mechanism?

A. Yes. TEP is requesting a LFCR to recover kWh sales that are lost as a result of complying with the Commission's EE Rules and REST Rules. The mechanism is designed to recover lost margins (non-fuel) due to

[7] See Mr. Jones testimony page 56

reductions in kWh sales as a result of these programs. "The LFCR that the Company is requesting is very similar to the Commission-approved mechanisms in the APS and UNS Gas rate cases that were decided earlier this year."[8]

Q. Can you please explain how the LFCR will work as proposed by the Company?

A. In summary, the LFCR will work as follows:

(1) Quantify the lost level of kWh sales by class from EE programs;

(2) Quantify the lost level of kWh sales by class from DG and net metering programs; (3) Adjust for any residential customers who have chosen to contribute to the lost margins in the form of a fixed margin; (4) Price the lost kWh sales in each class by the tail block margin rate if no Demand Charge is in place for that rate class, or the per kWh rate plus one half of the value of the Demand Charges for the class if Demand Charges are in place for that class; (5) Compare the total dollars recovered from the last year based on actual sales and determine if any over or under collection has occurred; (6) Add any carryover from the prior year (amount that the prior year's year-over-year increase was in excess of 2 percent of total revenues) and any over or under collection from the prior year;

(7) Compare this total to the total estimated retail revenues for the Company; (8) Carryover any amount the year over year increase is in

[8] See Mr. Jones testimony page 57

excess of 2 percent; (9) Add in the prior year's allowed amount to the allowed amount for the current year and divide this amount by the forecasted total sales for the Company to determine the per kWh rate application for the subsequent year; and (10) Submit these calculations and the proposed tariffs to the Commission by May 15 or each year for an anticipated effective date of July1.

Q. Will TEP's LFCR mechanism provide an "opt-out" provision for residential ratepayers?

A. Yes. Residential ratepayers will have the option of choosing a fixed monthly charge if they prefer not to be charged the variable rate based on kWh usage. The Company has proposed a fixed monthly option of $2.50 in months where usage is less that 2,000 kWh and will increase to $6.50 for the months when usage exceeds 2,000 kWh.

Q. Has TEP proposed an annual LFCR incremental cap that can be passed through to affected ratepayers?

A. Yes. The Company has proposed an annual 2 percent year over year cap based on total retail sales to all customers.

Q. Has the Company estimated the initial impact on ratepayers in the LFCR mechanism is approved by the Commission?

A. Yes. The Company has estimated that the initial impact on customer billings will be $0.004 per kWh effective July 1, 2014. (Lost margins are estimated at $36 million cumulative for years 2012 and 2013). If each year were considered separately the adjustment would be $0.002 kWh for each individual year. Based on estimated total kWh for each year the estimated rate payer affect will be within the 2 percent annual cap as proposed.

Q. What has been RUCO's position on adjustor mechanisms in past rate applications?

A. RUCO has opposed adjustor mechanisms in many rate applications in the past. However, RUCO has also recommended that adjustors be approved by the Commission when the circumstances warrant. For example, RUCO agreed with the ACRM (Arsenic Cost Recovery Mechanism) when the Federal Government changed the level of acceptable arsenic contained in water. RUCO has agreed with a LFCR with an opt out in the recent APS and UNS gas cases. Given that the Commission has mandated that TEP comply with certain Energy Efficiency programs a partial adjustor mechanism is appropriate provided that the customer have the option to opt out.

Q. Does RUCO agree with LFCR as proposed by TEP?

A. RUCO agrees with the concept of the LFCR mechanism as proposed by TEP with several changes. Again, RUCO has agreed to this limited form of adjustor mechanism to meet the Commission's Energy Efficiency Standard going forward because of the ratepayer's option to a fixed monthly rate.

Q. Does RUCO agree with the 2 percent cap on total company annual revenues as proposed by the Company?

A. No. RUCO believes that a 2 percent cap is high and a more appropriate cap should be set a one percent, including the first year the adjustor goes into place. A one percent cap has been approved by the Commission in Decisions related to both APS and UNS Gas. Any amount in excess of the one percent would be deferred for collection until the first future period in which such costs would not cause the annual increase to exceed the cap. Interest would be calculated on the deferred balance at the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 and will be adjusted annually.

Q. Does RUCO agree with the Company's "opt-out" provision as proposed by the Company?

A. RUCO agrees with an "opt-out" provision as it provides rate stability and provides a better price signal to encourage reduced consumption.

However, RUCO believes that the proposed cost of the "opt-out" provision presents an excessive burden to residential ratepayers. The average bill for residential ratepayers is $95.00 and compared to the lowest "opt-out" provision of $2.50, the increase to the average ratepayer, for the LFCR mechanism would be approximately 2.6 percent. RUCO believes that a maximum increase for the "opt-out" provision should be no more than one percent.

Q. Has RUCO reviewed the Plan of Administration (POA) as proposed by TEP?

A. Yes. RUCO has reviewed the POA and is proposing two changes. The first change to the POA is the reporting dates to the Commission. RUCO believes that submitting Compliance Reports by May 15th of each year and expecting a turn around by July 1st doesn't provide the ACC Staff with sufficient time for review. A later date in the year should be identified.

The second change that RUCO proposes to the POA is in Section 3, LFCR ANNUAL INCREMENTAL CAP. The Company has proposed that in the first year of implementing the adjustor the cap should be more than the cap in future years. RUCO recommends that one percent be the cap for all years in going forward including the initial year of implementation.

Energy Efficiency Resource Plan

Q. Can you please describe the Energy Efficiency Resource Plan, "EERP" that the Company is proposing?

A. TEP proposes the EERP as a "pilot program" to address the challenges the Company has faced implementing the EE programs." The EERP is a 3 year plan period commencing August 1, 2013. It proposes annual EE budgets of approximately $24 million to $27 million per year. The EERP capitalizes the program costs of the Plan and amortizes recovery over a 4 year period. It applies a "Performance Incentive" to the amount spent on EE calculated as the authorized Rate of Return plus a 200 basis point premium added to the cost of equity and recovers it over the same 4 year period. The EERP creates a regulatory asset for recovery of the revenues spent on EE programs.

TEP's proposal includes a Plan of Administration that includes a Societal Cost Test Template that TEP would use to determine cost effectiveness. It also authorizes TEP to select and administer DSM/EE programs it independently determines to be cost effective over the three years of the EERP consistent with the approved annual budget.

Q. What is RUCO's proposal regarding TEP's EERP?

A. RUCO opposes the EERP because it is not in the best interest of ratepayers for the following reasons:

1. By capitalizing program costs and applying carrying costs, the ratepayers may end up paying more for the EE programs than if these costs were expensed.
2. The rate of return plus 200 basis points premium that is applied to the DSM/EE program costs constitutes a performance incentive that is not based on actual performance and rewards spending over the EE savings.
3. The 3 year term unnecessarily binds future Commissions to spending levels and program structure.
4. The EERP eliminates significant Commission oversight.

RUCO will supplement its testimony on TEP's EERP when it files its direct testimony on rate design.

Q. Does this conclude your testimony?

A. Yes.

ROBERT B. MEASE, CPA
Education and Professional Qualifications

EDUCATION

Bachelors Degree Business Administration / Accounting - Morris Harvey College.

Attended West Virginia School of Graduate Studies and studied Accounting and Public Administration

Attended numerous courses and seminars for Continuing Professional Educational purposes.

WORK EXPERIENCE

Controller
Knives of Alaska, Inc., Diamond Blade, LLC., and Alaska Expedition Company.

Financial Manager / CFO
All Saints Camp & Conference Center

Energy West, Inc.
Vice President, Controller

- Led team that succeeded in obtaining a $1.5 million annual utility rate increase
- Coached accountants for proper communication techniques with Public Service Commission, supervised 9 professional accountants
- Developed financial models used to negotiate an $18 million credit line
- Responsible for monthly, quarterly and annual financial statements for internal and external purposes, SEC filings on a quarterly and annual basis, quarterly presentations to Board of Directors and shareholders during annual meetings, coordinated annual audit
- Communication with senior management team, supervised accounting staff and resolved all accounting issues, reviewed expenditures related to capital projects
- Monitored natural gas prices and worked with senior buyers to ensure optimal price obtained

Junkermier, Clark, Campanella, Stevens
Consulting Staff

- Established a consulting practice that generated approximately $160k the first year of existence
- Prepared business plan and projections for inclusion in clients financing documents
- Prepared written reports related to consulting engagements performed
- Developed models used in financing documents and made available for other personnel to use
- Performed Profit Enhancement engagements
- Participated during audit of large manufacturing client for two reporting years

Prior to 1999, held various positions: TMC Sales, Inc. as **Vice President / Controller**, with American Agri-Technology Corporation as **Vice President / CFO** and with Union Carbide Corporation as A**ccounting Manager. (Union Carbide was a multi-national Fortune 500 Company that was purchased by Dow Chemical)**

PROFESSIONAL AFFILIATIONS
Member - Institute of Management Accountants
Member - American Institute of CPA's
Past Member –WV Society of CPA's and Montana Society of CPA's

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REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,519,073	$ 3,041,359	$ 2,280,216	$ 1,237,439	$ 2,583,004	$ 1,910,221
2							
3	Adjusted Operating Income (Loss)	$ 52,471	$ 52,471	$ 52,471	$ 81,454	$ 81,454	$ 81,454
4							
5	Current Rate Of Return (Line 3 / Line 1)	3.45%	1.73%	2.30%	6.58%	3.15%	4.26%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 129,484	$ 129,484	$ 129,484	$ 97,612	$ 97,612	$ 97,612
8							
9	Weighted Average Cost of Capital	7.74%	7.74%	7.74%	7.28%	7.28%	7.28%
10							
11	Fair Value Adjustment	0.78%	-3.48%	-2.06%	0.61%	-3.50%	-2.17%
12							
13	Required Rate of Return	8.52%	4.26%	5.68%	7.89%	3.78%	5.11%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 77,013	$ 77,013	$ 77,013	$ 16,158	$ 16,158	$ 16,158
16							
17	Gross Revenue Conversion Factor (Schedule RBM-1, page 2)	1.6590	1.6590	1.6590	1.6574	1.6574	1.6574
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 127,765	$ 127,765	$ 127,765	$ 26,781	$ 26,781	$ 26,781
20							
21	Adjusted Test Year Revenue	$ 836,938	$ 836,938	$ 836,938	$ 873,082	$ 873,082	$ 873,082
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 964,703	$ 964,703	$ 964,703	$ 899,863	$ 899,863	$ 899,863
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	15.27%	15.27%	15.27%	3.07%	3.07%	3.07%
26							
27	Rate Of Return On Common Equity	10.75%	10.75%	10.75%	10.00%	10.00%	10.00%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules RBM-1, Page 2, RBM-2, RBM-7 and RBM-22
Column (E): Schedule RBM-2, Column (F)
Column (F): Average of Column (D) + Column (E)

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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		100.00%
2	Less: Uncollectibles	Per Company Workpapers	0.25%
3	Subtotal	Line 1 - Line 2	99.75%
4	Less: Combined Federal And State Tax Rate	Line 16	39.42%
5	Subtotal	Line 3 - Line 4	60.34%
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6574**
7			
8	CALCULATION OF EFFECTIVE TAX RATE:		
9	Arizona Taxable Income		100.0%
10	Arizona State Income Tax Rate		6.968%
11	Federal Taxable Income	Line 9 - Line 10	93.0%
12	Applicable Federal Income Tax Rate		35.0%
13	Effective Federal Income Tax Rate	Line 11 X Line 12	32.5%
14	Subtotal	Line 10 + Line 13	39.5%
15	Revenue Less Uncollectibles	Line 3	99.8%
16	Combined Federal And State Income Tax Rate	Line 14 X Line 15	39.4%
17			
18			
19			
20			
21			
22	Operating Income Deficiency	Sch RBM-1 Ln 15	$ 16,158
23	Gross Income Conversion Fzctor	Column (A) Ln 6	1.6574
24	Increase in Gross Revenue		$ 26,781
25			
26	Increase in Income Tax Expense	Ln 24 - Ln 22	$ 10,623
27			
28			

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FAIR VALUE RATE BASE
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 3,199,453	$ 6,655,502	$ 4,927,478	208.02%	$ 2,969,301	$ 6,176,741	$ 4,573,021
2	Accumulated Depreciation	(1,411,639)	(3,005,492)	(2,208,566)	212.91%	(1,277,931)	(2,720,816)	(1,999,373)
3	Net Utility Plant In Service	$ 1,787,814	$ 3,650,010	$ 2,718,912		$ 1,691,371	$ 3,455,924	$ 2,573,647
4								
5	Plant Held For Future Use	$ -	$ -	$ -	100.00%	$ -	$ -	$ -
6								
7	Total Net Utility Plant	$ 1,787,814	$ 3,650,010	$ 2,718,912		$ 1,691,371	$ 3,455,924	$ 2,573,647
8								
9	Deductions:							
10	Cust. Advances For Const.	$ (8,924)	$ (13,182)	$ (11,053)	147.71%	$ (8,924)	$ (13,182)	$ (11,053)
11	Customer Deposits	(23,743)	(23,743)	(23,743)	100.00%	(23,743)	(23,743)	(23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(15,832)	(15,773)	(15,803)	99.63%	(15,832)	(15,773)	(15,803)
13	Acc. Deferred Income Taxes	(284,654)	(620,365)	(452,510)	217.94%	(351,705)	(766,494)	(559,100)
14	Total Deductions	$ (333,153)	$ (673,063)	$ (503,108)		$ (400,204)	$ (819,192)	$ (609,698)
15								
16	Allowance - Working Capital	$ 53,323	$ 53,323	$ 53,323	100.00%	$ 49,057	$ 49,057	$ 49,057
17								
18	Regulatory Assets	$ 11,089	$ 11,089	$ 11,089	100.00%	$ -	$ -	$ -
19								
20	Regulatory Liability	$ -	$ -	$ -	100.00%	$ (102,785)	$ (102,785)	$ (102,785)
21								
22								
23	**TOTAL TEST YEAR RATE BASE**	$ 1,519,073	$ 3,041,359	$ 2,280,216		$ 1,237,439	$ 2,583,004	$ 1,910,221

References:
- Columns (A) (B) (C): Company Schedule B-1
- Column (D): Column (B) / Column (A)
- Column (E): Schedule RBM-3 page 1, Column (C)
- Column (F): Column (D) X Column (E)
- Column (G): Average Of Column (E) + Column (F)

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Schedule RBM-3

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 3,199,454	$ (230,153)	$ 2,969,301
2	Accumulated Depreciation	(1,411,639)	133,708	(1,277,931)
3	Net Utility Plant In Service	$ 1,787,815	$ (96,444)	$ 1,691,371
4				
5	Plant Held For Future Use	$ -	$ -	$ -
6				
7	Total Net Utility Plant	$ 1,787,815 0	$ (96,444)	$ 1,691,371
8				
9	Deductions:			
10	Cust. Advances For Const.	$ (8,924)	$ -	$ (8,924)
11	Customer Deposits	(23,743)	-	(23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(15,832)	-	(15,832)
13	Acc. Deferred Income Taxes	(284,654)	(67,051)	(351,705)
14	Total Deductions	$ (333,153)	$ (67,051)	$ (400,204)
15				
16	Allowance - Working Capital	$ 53,323	$ (4,266)	$ 49,057
17				
18	Regulatory Assets	$ 11,089	$ (11,089)	$ -
19				
20	Regulatory Liability	$ -	$ (102,785)	$ (102,785)
21				
22				
23	TOTAL OCRB	$ 1,519,074	$ (281,635)	$ 1,237,439

References:
Column (A): - Company Schedule B-2. Also see RBM-3 page 2 Col. A
Column (B): - RUCO Adjustments (See RBM-3 page 2, Columns (B) thru (G))
Column (C): - Sum Of Columns (A) and (B)

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

SUMMARY ORIGINAL COST RATE BASE - RUCO ADJUSTMENTS
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) Adjustment No. 1 Gross Utility Plant	(C) Adjustment No. 2 Accumulated Depreciation	(D) Adjustment No.3 Accu Deferred Income Taxes	(E) Adjustment No.4 Regulatory Liabilities	(F) Adjustment No.5 Sahuarita-Nogales Trans. Line	(G) Adjustment No. 5	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 3,199,454	$ (230,153)	-		$ -	$ -	$ -	$ 2,969,301
2	Accumulated Depreciation	(1,411,639)	-	133,708	-	-	-	-	(1,277,931)
3	Net Utility Plant In Service	$ 1,787,815	$ (230,153)	$ 133,708	$ -	$ -	$ -	$ -	$ 1,691,371
4									
5	Plant Held For Future Use	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6									
7	Total Net Utility Plant	$ 1,787,815 0	$ (230,153)	$ 133,708	$ -	$ -	$ -	$ -	$ 1,691,371
8									
9	Deductions:								
10	Cust. Advances For Const.	$ (8,924)	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,924)
11	Customer Deposits	(23,743)	-	-	-	-	-	-	(23,743)
12	Def'd Credit - Plt & Retm't	(15,832)	-	-	-	-	-	-	(15,832)
13	Acc. Deferred Income Taxes	(284,654)	-	-	(67,051)	-	-	-	(351,705)
14	Total Deductions	$ (333,153)	$ -	$ -	$ (67,051)	$ -	$ -	$ -	$ (400,204)
15									
16	Allowance - Working Capital	$ 53,323	$ -	$ -	$ -	$ -	$ -	$ (4,266)	$ 49,057
17									
18	Regulatory Assets	$ 11,089	$ -	$ -			$ (11,089)	$ -	$ -
19									
20	Regulatory Liability	$ -	$ -		$ -	$ (102,785)	$ -	$ -	$ (102,785)
21									
22									
23	TOTAL OCRB	$ 1,519,074	$ (230,153)	$ 133,708	$ (67,051)	$ (102,785)	$ (11,089)	$ (4,266)	$ 1,237,439

References:
Column (A): Company Schedule B-1
Columns (B) Thru (G): RUCO Rate Base Adjustment Nos. 1 thru 5
Column (H): Sum Of Columns (A) Through (G)

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

ORIGINAL COST RATE BASE STATEMENT WITH COMPANY ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB PRIOR TO ADJUSTMENTS	(B) Sahuarita-Nogales Transmission Line	(C) LH Improvements UniSource Energy Headquarters	(D) Post Test Year	(E) Post Test Yr Renewable	(F) Delayed Plant	(G) Acc Deferred ITC	(H) Acc Deferred Income Taxes	(I) Working Capital	(J) Total Adjustments	(K) COMPANY OCRB AFTER ADJUSTMENTS
1	Gross Utility Plant In Service	$ 3,156,974	$ -	$ (2,059)	$ 20,469	$ 16,413	$ 7,657	$ -	$ -	$ -	$ 42,480	$ 3,199,454
2	Accumulated Depreciation	(1,412,197)	-	(1,294)	28	702	6	-	-	-	$ (558)	$ (1,411,639)
3	Net Utility Plant In Service	$ 1,744,777	$ -	$ (765)	$ 20,441	$ 15,711	$ 7,651	$ -	$ -	$ -	$ 43,038	$ 1,787,815
4												
5	Plant Held For Future Use	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6												
7	Total Net Utility Plant	$ 1,744,777 0	$ -	$ (765)	$ 20,441	$ 15,711	$ 7,651	$ -	$ -	$ -	$ 43,038	$ 1,787,815
8												
9	Deductions:											
10	Cust. Advances For Const.	$ (8,924)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,924)
11	Customer Deposits	(23,743)	-	-	-	-	-	-	-	-	$ -	$ (23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(14,227)	-	-	-	-	-	(1,605)	-	-	$ (1,605)	$ (15,832)
13	Acc. Deferred Income Taxes	(158,005)	-	-	-	-	-	-	(126,649)	-	$ (126,649)	$ (284,654)
14	Total Deductions	$ (204,899)	$ -	$ -	$ -	$ -	$ -	$ (1,605)	$ (126,649)	$ -	$ (128,254)	$ (333,153)
15												
16	Allowance - Working Capital	$ 88,084	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,761)	$ (34,761)	$ 53,323
17												
18	Regulatory Assets	$ -	$ 11,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,089	$ 11,089
19												
20	Regulatory Liability	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21												
22											$ -	
23	TOTAL OCRB	$ 1,627,962	$ 11,089	$ (765)	$ 20,441	$ 15,711	$ 7,651	$ (1,605)	$ (126,649)	$ (34,761)	$ (108,888)	$ 1,519,074

References:
Column (A) thru Column (K): - Company Schedule B-2

RATE BASE ADJUSTMENT NO. 1
GROSS UTILITY PLANT IN SERVICE
(Thousands of Dollars)

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Gross Utility Plant in Service	$ 3,199,454	$ (230,153)	2,969,301
2				
3				
4				
5				
6				
7				
8	Gross Utility Plant Reduction	$ 162,181,320	See RBM-5 page 1 Ln 44	
9			and FWR Testimony	
10	ACC Jurisdictional Costs of New Building	67,971,337		
11				
12	TOTAL ADJUSTMENTS	$ 230,152,657		
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23	References:			
24	Column (A) Ln 1 - Company Workpapers			
	Column (A) Ln 10 - Company Response to Staff Data Request 23.6			

Tucson Electric Power Company
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Test Year Ended December 31, 2011

RATE BASE ADJUSTMENT NO. 2
ACCUMULATED DEPRECIATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Accumulated Depreciation	$ (1,411,638,679)	$ 133,708,325	$ (1,277,930,354)
2				
3				
4				
5				
6				
7				
8				
9				
10				
11	RUCO Proposed Adjustments			
12				
13	Reduction of A/D due to disallowance of plant in service		$ 4,557,838	RBM-5 page 1, Ln 44
14	Reduction of A/D due to depreciation expense increase			
15	resulting from reclassification of plant		3,922,727	RBM-5 page 1, Ln 36
16	Reduction of A/D due to disallowance of new office building		1,885,760	RBM-5 page 2, Ln 17
17	Reduction of A/D due to the return of depreciation			
18	reserve to ratepayers		20,557,214	RBM-4 page 4, Ln 10
19	Reclassification of A/D to Regulatory Liability			
20	($123,342,000 - $20,557,000)		102,784,786	RBM-4 page 4, Ln 8
21				
22				
23			$ 133,708,325	
24				

References:
Comumn (A) Company Schedule B-1

RATE BASE ADJUSTMENT NO. 3
ACCUMULATED DEFERRED INCOME TAXES

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Accumulated Deferred Income Taxes	$ (284,653,882)	$ (67,051,372)	$ (351,705,254)
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12	Net Operating Losses Carry Forwards (NOL)			
13				
14	FED & NM NOL CARRYFORWARD	$ 82,071,149		
15	Post Test Year Plant NOL	3,161,209		
16	Delayed Plant Adj. NOL	2,722,567		
17	AZ NOL Carryforward	1,256,587		
18				
19	Deferred Tax Asset Resulting from NOL	$ 89,211,512		
20				
21	ACC Jurisdictional	75.16%		
22				
23	RUCO ADJUSTMENT	$ 67,051,372		
24				

References:
Column (A) Company Schedules
Column (A) Lns 14 thru 23Company URD-1 Schedule Attachments and Workpapers

Tucson Electric Power Company
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Test Year Ended December 31, 2011

RATE BASE ADJUSTMENT NO. 4
REGULATORY LIABILITIES

Line No.	Acct	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	254	Regulatory Liabilities	$ -	$ (102,784,786)	$ (102,784,786)
7		RUCO's proposed reduction in Accumulated Depreciation			
8		due to difference in book A/D and theoretical depreciation		123,342,000	FWR Testimony
10		Six year amortization		20,557,000	FWR Testimony
12		Remaining Unamortized Regulatory Liability		$ 102,785,000	

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Test Year Ended December 31, 2011

RATE BASE ADJUSTMENT NO. 5
REGULATORY ASSETS

Acct	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
182.3	Regulatory Assets	$ 11,088,732	$ (11,088,732)	$ -

Pre-Construction Costs	$ 8,947,914
Land and Land Rights	2,140,815
	$ 11,088,729

RUCO is proposing that the total cost of the Sahuarita Nogales Transmission Line be deleted from rate base. The total cost included in rate base related to the line is $11,088,732 which includes pre-construction cost as well as land and and land rignts.

The Company is proposing that the pre-construction costs of the Sahuarita Nogales Transmission Line be amortized over a three year period or $2,982,638 per year.

Tucson Electric Power Company
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RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	REFERENCE		(A) AMOUNT
1	Cash Working Capital Per TEP	TEP SCH. B-5, Page 1	$	(19,359)
2	Cash Working Capital Per RUCO	RBM-6		(23,625)
3	Adjustment	Line 2 - Line 1	$	(4,266)
4				
5	Fuel Inventory Per TEP	TEP SCH. B-5, Page 1	$	25,307
6	Fuel Inventory Per RUCO	TEP SCH. B-5, Page 1		25,307
7	Adjustment	Line 6 - Line 5	$	-
8				
9	Materials And Supplies Per TEP	TEP SCH. B-5, Page 1	$	42,837
10	Materials And Supplies Per RUCO	TEP SCH. B-5, Page 1		42,837
11	Adjustment	Line 10 - Line 9	$	-
12				
13	Prepayments Per TEP	TEP SCH. B-5, Page 1	$	4,538
14	Prepayments Per RUCO	TEP SCH. B-5, Page 1		4,538
15	Adjustment	Line 14 - Line 13	$	-
16				
17	TOTAL ADJUSTMENT - WORKING CAPITAL	Sum Lines 3, 7, 11, 15)	$	(4,266)
18				
19				
20				
21				
22				

Tucson Electric Power Company
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Test Year Ended December 31, 2011

TEST YEAR PLANT ADJUSTMENTS

Acct.	2006 Gross Plant	2006 Depre Reserve	2006 Net Plant	2011 Gross Plant	2011 Depre Reserve	2011 Net Plant	Depre Rate	RUCO ADJUSTED 2011 Gross Plant	Depr Res on 2006 Balance	Growth in Reserve Balance	Total Depre Reserve	Net Plant	Prop Depre Rate	DEPRECIATION EXPENSE Depreciation Expense Company	Depreciation Expense RUCO	Difference
Steam Production Plant																
310	$ 4,603	$ 2,243	$ 2,360	$ 4,603	$ 3,874	$ 729	5.34%	$ 4,603	$ 3,472	$ 181	$ 3,653	$ 950	1.58%	73	73	-
311	111,087	62,031	49,056	168,247	97,520	70,727	5.16%	160,816	90,691	3,073	93,764	67,052	2.32%	3,903	3,731	(172)
312	652,151	332,664	319,487	1,020,623	489,561	531,062	3.87%	972,722	458,855	13,818	472,673	500,049	3.03%	30,925	29,473	(1,451)
314	206,960	101,243	105,717	300,048	140,860	159,188	3.79%	287,947	140,462	179	140,641	147,306	3.67%	11,012	10,568	(444)
315	71,511	38,182	33,329	116,382	59,751	56,631	3.24%	110,549	49,767	4,493	54,260	56,289	3.66%	4,260	4,046	(213)
316	19,281	10,338	8,943	22,314	13,826	8,488	3.88%	21,556	14,079	(114)	13,965	7,591	2.73%	609	588	(21)
317	70	56	14	-		-		9	-	-	-				-	
	$ 1,065,663	$ 546,757	$ 518,906	$ 1,632,217	$ 805,392	$ 826,825		$ 1,558,201	$ 757,326	$ 21,630	$ 778,956	$ 779,236		50,781	48,479	(2,302)
Distribution Plant																
360	$ 7,991	$ 2,895	$ 5,096	$ 8,018	$ 3,543	$ 4,475	1.43%	8,011	3,466	7	3,473	4,537	1.43%	115	115	(0)
361	6,282	1,745	4,537	11,107	2,122	8,985	1.63%	9,804	2,257	(12)	2,245	7,559	1.72%	191	169	(22)
362	95,451	63,750	31,701	138,343	42,910	95,433	1.46%	126,762	70,718	(2,503)	68,215	58,547	1.53%	2,117	1,939	(177)
364	112,985	80,761	32,224	159,393	51,948	107,445	1.63%	146,863	89,969	(3,422)	86,547	60,315	1.74%	2,773	2,555	(218)
365	106,758	59,379	47,379	152,686	55,045	97,641	1.47%	140,285	67,226	(1,096)	66,129	74,156	1.63%	2,489	2,287	(202)
366	49,342	15,411	33,931	53,276	23,337	29,939	1.42%	51,584	18,914	398	19,312	32,272	1.35%	719	696	(23)
367	213,374	46,664	166,710	268,486	104,292	164,194	1.89%	253,606	66,828	3,372	70,200	183,406	1.87%	5,021	4,742	(278)
368	77,837	35,429	42,408	103,782	47,865	55,917	1.84%	96,777	42,590	475	43,065	53,712	1.87%	1,941	1,810	(131)
368	125,291	44,936	80,355	164,679	71,693	92,986	2.52%	147,742	60,723	987	61,710	86,032	2.09%	3,442	3,088	(354)
369	12,050	4,425	7,625	15,071	5,414	9,657	1.62%	14,255	5,401	1	5,402	8,853	1.85%	279	264	(15)
369	79,968	38,184	41,784	98,682	33,223	65,459	1.50%	93,629	44,182	(986)	43,195	50,434	1.52%	1,500	1,423	(77)
370	32,881	11,285	21,596	45,714	14,857	30,857	2.99%	42,249	16,201	(121)	16,080	26,169	3.29%	1,504	1,390	(114)
373	9,334	5,835	3,499	11,173	4,814	6,359	1.74%	10,676	6,647	(165)	6,482	4,194	1.77%	198	189	(9)
374	216	183	33	-		-	0.00%	-	-							
	$ 929,760	$ 410,882	$ 518,878	$ 1,230,410	$ 461,063	$ 769,347		$ 1,142,245	$ 495,121	$ (3,065)	$ 492,056	$ 650,188		$ 22,288	$ 20,667	$ (1,621)
Total	$ 1,995,423	$ 957,639	$ 1,037,784	$ 2,862,627	$ 1,266,455	$ 1,596,172		$ 2,700,446	$ 1,252,447	$ 18,564	$ 1,271,012	$1,429,425		$ 73,069	$ 69,146	$ (3,923)

ADJUSTMENT TO GROSS UTILITY PLANT

Steam Plant as Submitted by Company	$ 1,632,217
Steam Plant Recomputed by RUCO	$ 1,558,201
Decrease in Gross Value Steam Plant	$ 74,016
Distribution Plant as Submitted by Company	$ 1,230,410
Distribution Plant Recomputed by RUCO	$ 1,142,245
Decrease in Gross Value Dist. Plant	$ 88,165
Total Reduction in Plant	$ 162,181,320

ACCUMULATED DEPRECIATION ADJUSTMENT

Steam Plant as Submitted by Company	$ 805,392
Steam Plant Recomputed by RUCO	$ 778,956
Decrease in A/D - Steam Plant	$ 26,436
Distribution Plant as Submitted by Company	$ 461,063
Distribution Plant Recomputed by RUCO	$ 492,056
Decrease in A/D - Distribution Plant	$ (30,993)
Total Reduction in A/D	$ (4,556,838)

DEPRECIATION EXPENSE ADJUSTMENT

$ (3,922,727)

BUILDING COSTS ALLOCATED TO AFFILIATES

Line		(A)		Sq FT	$ per sq foot	Annual Revenue Requirment ($ millions)
1	Investment in Land-downtown HQ	$ 8,549,938				
2	Investment in Office Facilities	71,430,308				
3	Investment in Furniture & Equipment	50,023				
4	Less: Accumulated Depreciation	(901,025)				
5	Less: Accumulated Depreciation	(1,176,718)				
6	Less: Accumulated Deferred Income Taxes	-				
7	Net Investment in Office Facilities	77,952,526				
8	Multiplied by: Current Regulated Rate of Return	8.03%				
9						
10	Required Return on Office Facilities and F&E	6,259,588				
11						
12	Add:					
13	O&M Expenses Applicable to Office Facilities and F&E	2,100,000	RBM-19			
14	PC/Lan Expenses	-				
15	Property Taxes Applicable to Office Facilities	1,000,000	RBM-20			
16	Insurance Costs Applicable to Office Facilities	-				
17	Book Depreciation on Office Facilities	1,885,760	RBM-10			
18	Income Taxes on Equity Portion of Return **	2,225,597				
19						
20	Revenue Requirement for Office Facilities and F&E	13,470,945		232,835	57.86	$ 13,470,945
21						
22	Diveded by: Number of Employees - Excluding SPG	539			25.00	$ 5,820,875
23						
24	Cost Per Employee	$ 24,992	Calculated IncomeAffects of Bldg			$ (7,650,070)
25						
26	Divided by: Annual Labor Hrs.	2,080				
27						
28	**Facilities Cost Per Hour**	**$ 12.02**				
29						
30	**					
31	Net Investment in Office Facilities	$ 77,952,526				
32	Regulated Rate of Return - Equity Component	4.36%				
33	Equity Component of Return on Office Facilities	3,398,730				
34	Divide by 1- Combined Tax Rate	60.4291%				
35		5,624,327				
36	Multiply by Combined Tax Rate	39.5709%				
37	Income Taxes on Equity Portion of Return	$ 2,225,597				
38						

References:
Company Data Response
See FWR Testimony

ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requirements
						-	-	-	-
	OPERATING EXPENSES								
	Non-Cash Expenses:								
1	Bad Debts Expense	$ 2,080,293	$ (2,080,293)	-			-		$ -
2	Depreciation	119,580,496	$ (119,580,496)	-			-		-
3	Amortization	3,481,610	$ (3,481,610)	-			-		-
4	Deferred Income Taxes	12,803,088	$ (12,803,088)	-			-		-
5	Total Non-Cash Expenses	$ 137,945,487	$ (137,945,487)	$ -					$ -
	Other Operating Expenses:								
6	Salaries & Wages	$ 71,991,108	$ (1,470,721)	$ 70,520,387	36.47	10.46	26.01	7.13%	$ 5,025,302
7	Incentive Pay	6,247,890	(2,530,620)	3,717,270	36.47	259.50	(223.03)	-61.10%	(2,271,404)
8	Fuel Expense	285,386,416	-	285,386,416	36.47	29.50	6.97	1.91%	5,449,708
9	Lease Expense	101,812,888	-	101,812,888	36.47	94.33	(57.86)	-15.85%	(16,139,435)
10	Remote Generating Plant O & M	47,385,627	(4,883,016)	42,502,611	36.47	(6.90)	43.37	11.88%	5,050,242
11	Office Supplies and Expenses	9,594,745	-	9,594,745	36.47	12.46	24.01	6.58%	631,150
12	Outside Services	10,520,391	-	10,520,391	36.47	44.51	(8.04)	-2.20%	(231,737)
13	Property Insurance	2,271,746	(289,320)	1,982,426	36.47	-	36.47	9.99%	198,080
14	Injuries and Damages	2,278,506	-	2,278,506	36.47	(13.27)	49.74	13.63%	310,501
15	Pensions and Benefits	17,449,591	-	17,449,591	36.47	13.03	23.44	6.42%	1,120,598
16	Misc. General Expenses	4,285,497	(2,139,016)	2,146,481	36.47	(2.00)	38.47	10.54%	226,233
17	Rents	375,864	-	375,864	36.47	(40.51)	76.98	21.09%	79,271
18	Property Taxes	39,148,092	(3,110,547)	36,037,545	36.47	213.78	(177.31)	-48.58%	(17,506,348)
19	Payroll Taxes	7,830,466	$ (272,631)	7,557,835	36.47	16.53	19.94	5.46%	412,886
20	Current Income Taxes	7,016	22,763	29,779	36.47	62.05	(25.58)	-7.01%	(2,087)
21	Other Taxes	46,168	-	46,168	36.47	91.37	(54.90)	-15.04%	(6,944)
22	Interest on Customer Deposits	(2,439)	-	(2,439)	36.47	182.50	(146.03)	-40.01%	976
23	Other Operations and Maint.	63,312,707	(149,998)	63,162,709	36.47	11.99	24.48	6.71%	4,236,228
24	Total Other Operating Exp.	$ 669,942,279	$ (14,823,108)	$ 655,119,171					$ (13,416,781)
25									
26	Other Cash Working Capital Elements:								
27	Interest on Long-Term Debt	$ 54,838,713	$ -	54,838,713	36.47	86.20	(49.73)	-13.62%	$ (7,471,587)
28	Rev. Taxes and Assessments	85,440,494	-	85,440,494	36.47	48.16	(11.69)	-3.20%	$ (2,736,437)
29	Total Other Cash Working Cap.	$ 140,279,207	$ -	$ 140,279,207					$ (10,208,023)
30									
31	TOTAL CASH WORKING CAPITAL	$ 948,166,973		$ 795,398,378					$ (23,624,804)
32									
33									
34									
35									

36 References:
37 Column (A): - Company Schedule B-5
38 Column (B): RUCO Operating Income Adjustments (See RBM-8)
39 Column (C): Column (A) + (B)
40 Column (D): Company Schedule B-5, Page 3
41 Column (E): Column (C) X Column (D)

Tucson Electric Power Company
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Test Year Ended December 31, 2011

Schedule RBM-7
Page 1

OPERATING INCOME STATEMENT
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D	(E) RUCO PROPOSED ACC JURID'L	(F) RUCO RECOM'D ACC JURID'L
1	Operating Revenues:					
2	Electric Retail Revenues	$ 836,938	$ -	$ 836,938	$ 26,781	$ 863,719
3	Sales for Resale	-	-	-		
4	Other Operating Revenue	$ 29,183	6,961	36,144	-	$ 36,144
5						
6	TOTAL OPERATING REVENUES	$ 866,121	$ 6,961	$ 873,082	$ 26,781	$ 899,863
7						
8	Operating Expenses:					
9	Fuel, Purchased Power and Trans	$ 292,188	(6,692)	$ 285,496		$ 285,496
10	Other Operations and Maintenance Exp	381,988	(8,107)	373,881		373,881
11	Depreciation and Amortization	97,311	(26,366)	70,945		70,945
12	Taxes Other than Income Taxes	35,142	(3,383)	31,759		31,759
13	Income Taxes	7,019	22,525	29,544	10,623	40,167
14	Rounding Differences	-	2	2		2
15	TOTAL OPERATING EXPENSES	$ 813,648	$ (22,019)	$ 791,628	$ 10,623	$ 802,251
16						
17	OPERATING INCOME (LOSS)	$ 52,473	$ 28,980	$ 81,454	$ 16,158	$ 97,612

References:
Column (A) Per Company Filing
Column (B) Schedule RBM-8
Column (E) Schedule RBM-1 page 2

References:
Column (A): Company Schedule C-1
Column (B): Testimonies, RLM & MDC And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Column (C) X Jurisdictional Factor
Column (E): See Schedule RLM-1
Column (F): Column (D) + Column (E)

Tucson Electric Power Company
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Schedule RBM-8
Pages 1 through 6

OPERATING INCOME – RUCO ADJUSTMENTS

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) Adjustment 1 Springervilee Rental Income	(C) Adjustment 2 Depreciation	(D) Adjustment 3 Payroll Expense	(E) Adjustment 4 Incentive Compensation	(F) Adjustment 5 Payroll Tax Expense	(G) Adjustment 6 Nogales Amortization
1	440, 442, 444,445	**Electric Retail Revenue**	$ 836,937,887	$ -	$ -	$ -	$ -	$ -	$ -
2	446	**Sales for Resale**	-	-	-	-	-	-	-
3	447	**Total Electric Retail Revenue**	$ 836,937,887	$ -	$ -	$ -	$ -	$ -	$ -
4		**Other Operating Revenue**							
5	451	Miscellaneous Service Revenues	$ 5,806,044	$ -	$ -	$ -	$ -	$ -	$ -
6	454	Rent from Electric Property	23,259,549	6,961,004	-	-	-	-	-
7	456	Other Electric Revenues	116,375	-	-	-	-	-	-
8		**Total Other Operating Revenue**	$ 29,181,968	$ 6,961,004	$ -	$ -	$ -	$ -	$ -
9									
10		**Total Operating Revenue**	$ 866,119,855	$ 6,961,004	$ -	$ -	$ -	$ -	$ -
11		***Steam Power Generation Expense***							
12	500	Operation Supervision & Engineering	$ 10,018,926	$ -	$ -	$ (145,350)	$ (66,725)	$ -	$ -
13	501	Fuel - PPFAC Eligible	292,189,698	-	-	(15,982)	-	-	-
14	502	Steam Expenses	17,774,394	-	-	(155,551)	-	-	-
15	505	Electric Expenses	2,849,546	-	-	(47,962)	-	-	-
16	506	Miscellaneous Steam Power Expenses	7,105,981	-	-	(46,500)	(625,354)	-	-
17	507	Rents	85,647,219	-	-	-	-	-	-
18	510	Maintenance Supervision & Engineering	4,166,964	-	-	(57,268)	-	-	-
19	511	Maintenance of Structures	4,082,070	-	-	(13,325)	-	-	-
20	512	Maintenance of Boiler Plant	30,696,060	-	-	(135,031)	-	-	
21	513	Maintenance of Electric Plant	7,912,839	-	-	(37,219)	-	-	-
22	514	Maintenance Miscellaneous Steam Plant	7,750,254	-	-	(48,562)	(246,394)	-	-
23	411	FAS 143 Accretion Expense	-	-	-	-	-	-	-
24		Gain on Sales of Emission Allowances	-	-	-	-	-	-	-
25		**Total Steam Power Generation Expense**	470,193,951	-	-	(702,748)	(938,473)	-	-
26		**Other Power Generation Expenses**							
27	546	Operation Supervision & Engineering	3,765,468	$ -	$ -	$ (725)	$ -	$ -	$ -
28	547	Fuel - PPFAC Eligible	-	-	-	-	-	-	-
29	548 & 549	Misc. Other Power Generation	6,180			(103)			
30	550	Rents	-						
31	551	Maintenance Supervision & Engineering	124,929	-	-	-	-	-	-
32	552 - 554	Maintenance Plant	1,080,817	-	-	(2,903)	-	-	-
33	557	Other Expenses	630,823	-	-	(7,480)	-	-	-
34		**Total Power Generation Expense**	5,608,217	-	-	(11,210)	-	-	-
35		**Other Power Supply Expense**							
36	555	Purchased Power - Demand - PPFAC Eligible	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	555	Purchased Power - Energy - PPFAC Eligible	-	-	-	-	-	-	-
38	556	System Control and Load Dispatching	-	-	-	-	-	-	-
39		**Total Other Power Supply Expense**	-						
40		**TOTAL PRODUCTION EXPENSE**	475,802,168	-	-	(713,958)	(938,473)	-	-

Tucson Electric Power Company
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Schedule RBM-8
Pages 1 through 6

OPERATING INCOME – RUCO ADJUSTMENTS

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) Adjustment 1 Springervilee Rental Income	(C) Adjustment 2 Depreciation	(D) Adjustment 3 Payroll Expense	(E) Adjustment 4 Incentive Compensation	(F) Adjustment 5 Payroll Tax Expense	(G) Adjustment 6 Nogales Amortization
41									
42		**Transmission Non-EHV (138 KV & Below)**							
43	560	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	561 & 561.1 - 561.8	Load Dispatch & Various	-	-	-	-	-	-	-
45	562	Station Expenses	-	-	-	-	-	-	-
46	563	Overhead Line Expenses	-	-	-	-	-	-	-
47	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-
48	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-
49	569 & 569.1-569.3	Maint. of Structures & Computers (Hard & Software & Equip)	-	-	-	-	-	-	-
50	570	Maintenance of Station Equipment	-	-	-	-	-	-	-
51	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-
52	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-
53		**Total Transmission Non EHV (138 KN & Below)**					-		
54		**Transmission EHV (345kv & Above) Expense**							
55	560	Operation Supervision & Engineering	-	$ -	$ -	$ -	$ -	$ -	$ -
56	561 & 561.1 - 561.8	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-
57	562	Station Expenses	-	-	-	-	-	-	-
58	563	Overhead Line Expenses	-	-	-	-	-	-	-
59	565	Transmission of Electricity by Others - PPFAC Eligible	90,028,056	-	-	-	-	-	-
60	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-
61	567	Rents	-	-	-	-	-	-	-
62	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-
63	569 & 569.1 - 569.3	Maint. of Structures & Computers (Hard & Software & Equip)	-	-	-	-	-	-	-
64	570	Maintenance of Station Equipment	-	-	-	-		-	-
65	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-
66	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-
67		**Total Transmission EHV (345kv & Above) Expense**	90,028,056				-		
68									
69									
70									
71		**Distribution Expense**							
72	580	Operation Supervision & Engineering	$ 1,321,680	$ -	$ -	$ (18,065)	$ (47,590)	$ -	$ -
73	581	Load Dispatching	592,834	-	-	(9,604)	-	-	-
74	582	Station Expenses	230,240	-	-	(1,358)	-	-	-
75	583	Overhead Line Expenses	627,561	-	-	(7,850)	-	-	-
76	584	Underground Line Expenses	141,291	-	-	(2,765)	-	-	-
77	585	Street Lighting & Signal System Expenses	172,310	-	-	(100)	-	-	-
78	586	Meter Expenses	2,287,037	-	-	(22,663)	-	-	-
79	587	Customer Installations Expense	135,368	-	-	(2,580)	-	-	-
80	588	Miscellaneous Distribution Expenses	9,784,316	-	-	(70,533)	(192,022)	-	-
81	589	Rents	867,282	-	-	-	-	-	-
82	590	Maintenance Supervision & Engineering	780,444	-	-	(12,308)	-	-	-
83	591	Maintenance of Structures	-		-				
84	592	Maintenance of Station Equipment	1,088,984	-	-	(10,821)	-	-	-
85	593	Maintenance of Overhead Lines	925,427	-	-	(13,504)	-	-	-
86	594	Maintenance of Underground Lines	165,484	-	-	(1,497)	-	-	-
87	595	Maintenance of Line Transformers	494,257	-	-	(5,842)	-	-	-
88	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-
89	597	Maintenance of Meters	116,105	-	-	(2,249)	-	-	-
90	598	Maintenance of Miscellaneous Distribution Plant	252,158	-	-	(1,057)	(30,364)	-	-
91	407.3	Regulatory Asset Amortization	2,982,638	-	-	-	-	-	(2,982,638)
92		**Total Distribution Expense**	22,965,416	-	-	(182,797)	(269,975)	-	(2,982,638)

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OPERATING INCOME -- RUCO ADJUSTMENTS

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) Adjustment 1 Springervilee Rental Income	(C) Adjustment 2 Depreciation	(D) Adjustment 3 Payroll Expense	(E) Adjustment 4 Incentive Compensation	(F) Adjustment 5 Payroll Tax Expense	(G) Adjustment 6 Nogales Amortization
93		**Customer Account Expense**							
94	901	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	902	Meter Reading Expenses	3,037,059	-	-	-	-	-	-
96	903	Customer Records & Collection Expenses	13,230,911	-	-	(144,574)	(202,140)	-	-
97	904	Uncollectible Accounts	2,080,293	-	-	-	-	-	-
98	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-
99	908	Customer Assistance Expenses	967,950	-	-	(19,935)	-	-	-
100	909	Informational and Instructional Advertising Expenses	121,526	-	-	(662)	-	-	-
101	910	Miscellaneous Customer Service & Informational Expenses	14,638	-	-	-	-	-	-
102		**Total Customer Accounts Expense**	19,452,377	-	-	(165,171)	(202,140)	-	-
103		**Administrative and General Expense**							
104	920	Administrative & General Salaries	24,869,030	$ -	$ -	$ (359,093)	$ (1,120,032)	$ -	$ -
105	921	Office Supplies & Expenses	9,869,281	-	-	-	-	-	-
106	922	Administrative Expenses Transferred - Credit	(10,853,685)	-	-	-	-	-	-
107	923	Outside Services Employed	9,837,609	-	-	-	-	-	-
108	924	Property Insurance	2,539,551	-	-	-	-	-	-
109	925	Injuries and Damages	2,995,079	-	-	(9,924)	-	-	-
110	926	Employee Pension & Benefits	20,695,813	-	-	(31,542)	-	-	-
111	928	Regulatory Commission Expenses	1,200,636	-	-	-	-	-	-
112	929	Duplicate Charges - Credit	(301,307)	-	-	-	-	-	-
113	930.1	General Advertising Expenses	530,861	-	-	(8,235)	-	-	-
114	930.2	Miscellaneous General Expenses	4,118,952	-	-	-	-	-	-
115	931	Rents	332,450	-	-	-	-	-	-
116	935	Maintenance of General Plant	50,310	-	-	-	-	-	-
117		**TotalAdministrative and General Expense**	65,884,580	-	-	(408,794)	(1,120,032)	-	-
118		**Total Operation and Maintenance Expense**	$ 674,132,597	$ -	$ -	$ (1,470,721)	$ (2,530,620)	$ -	$ (2,982,638)
119		**Depreciation & Amortization - All**							
120	403/404/406	Intangible Plant	$ 9,331,228	$ -	$ -	$ -	$ -	$ -	$ -
121	403/404/406	Other Production Plant	52,018,787	-	-	-	-	-	-
122	403/404/406	Transmission Plant	-	-	(26,365,701)	-	-	-	-
123	403/404/406	Distribution Plant	25,609,770	-	-	-	-	-	-
124	403/404/406	General Plant	10,350,629	-	-	-	-	-	-
125		**Total Depreciation & Amortization - All**	$ 97,310,414	$ -	$ (26,365,701)	$ -	$ -	$ -	$ -
126		**Taxes Other Than Income Taxes**							
127	408	Property Tax - Production	$ 15,733,923	$ -	$ -	$ -	$ -	$ -	$ -
128	408	Property Tax - Other Production	-	-	-	-	-	-	-
129	408	Property Tax - Transmission (EHV & Non-EHV))	-	-	-	-	-	-	-
130	408	Property Tax - Distribution	13,059,052	-	-	-	-	-	-
131	408	Property Tax - General	1,719,601	-	-	-	-	-	-
132	408	Business Activity Tax - Generation	4,272	-	-	-	-	-	-
133	408	Business Activity Tax - Transmission	-	-	-	-	-	-	-
134	408	Other (Including Payroll Taxes)	4,624,641	-	-	-	-	(272,631)	-
135		**Total Taxes Other Than Income Taxes**	$ 35,141,489	$ -	$ -	$ -	$ -	$ (272,631)	$ -
136									
137	431	Customer Deposit Interest Expense	$ 45,852						
138									
139	409	Current Income Tax - State & Federal	$ 7,018,368						
140	410	Deferred IT - Federal & State (debits)	$ -						
141	411	Deferred IT - Federal & State (credits)	$ -						
142		**Total Income Taxes**	$ 7,018,368	$ -	$ -	$ -	$ -	$ -	$ -
143		**Total Operating Expense**	$ 813,648,720	$ -	$ (26,365,701)	$ (1,470,721)	$ (2,530,620)	$ (272,631)	$ (2,982,638)
		OPERATING INCOME (Test Year Adjusted)	$ 52,471,135	$ 6,961,004	$ 26,365,701	$ 1,470,721	$ 2,530,620	$ 272,631	$ 2,982,638

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OPERATING INCOME – RUCO ADJUSTMENTS

LINE NO.	FERC ACCT	DESCRIPTION	(H) Adjustment 7 Overhaul and Outage	(I) Adjustment 8 Injuries and Damages	(J) Adjustment 9 Officers and Directors Ins.	(K) Adjustment 10 Lime Expense	(L) Adjustment 11 Rate Case Expense	(M) Adjustment 13 Property Tax Expense	(N) Adjustment 12 Miscellaneous and General	(O) Adjustment 14 Income Tax Expense	(P) RUCO AS ADJUSTED
1	440, 442, 444,445	Electric Retail Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 836,937,887
2	446	Sales for Resale	-	-	-	-	-	-	-	-	-
3	447	Total Electric Retail Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 836,937,887
4		Other Operating Revenue									
5	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,806,044
6	454	Rent from Electric Property	-	-	-	-	-	-	-	-	30,220,553
7	456	Other Electric Revenues	-	-	-	-	-	-	-	-	116,375
8		Total Other Operating Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,142,972
9											
10		Total Operating Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 873,080,859
11		Steam Power Generation Expense									
12	500	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,806,851
13	501	Fuel - PPFAC Eligible	-	-	-	-	-	-	-	-	292,173,716
14	502	Steam Expenses	-	-	-	(149,998)	-	-	-	-	17,468,845
15	505	Electric Expenses	-	-	-	-	-	-	-	-	2,801,584
16	506	Miscellaneous Steam Power Expenses	-	-	-	-	-	-	-	-	6,434,127
17	507	Rents	-	-	-	-	-	-	-	-	85,647,219
18	510	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	4,109,696
19	511	Maintenance of Structures	-	-	-	-	-	-	-	-	4,068,745
20	512	Maintenance of Boiler Plant	(4,883,016)	-	-	-	-	-	-	-	25,678,013
21	513	Maintenance of Electric Plant	-	-	-	-	-	-	-	-	7,875,620
22	514	Maintenance Miscellaneous Steam Plant	-	-	-	-	-	-	-	-	7,455,298
23	411	FAS 143 Accretion Expense	-	-	-	-	-	-	-	-	-
24		Gain on Sales of Emission Allowances	-	-	-	-	-	-	-	-	-
25		Total Steam Power Generation Expense	(4,883,016)	-	-	(149,998)	-	-	-	-	463,519,715
26		Other Power Generation Expenses									
27	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,764,743
28	547	Fuel - PPFAC Eligible	-	-	-	-	-	-	-	-	-
29	548 & 549	Misc. Other Power Generation									
30	550	Rents									
31	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	124,929
32	552 - 554	Maintenance Plant	-	-	-	-	-	-	-	-	1,077,914
33	557	Other Expenses	-	-	-	-	-	-	-	-	623,343
34		Total Power Generation Expense	-	-	-	-	-	-	-	-	5,590,930
35		Other Power Supply Expense									
36	555	Purchased Power - Demand - PPFAC Eligible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	555	Purchased Power - Energy - PPFAC Eligible	-	-	-	-	-	-	-	-	-
38	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-
39		Total Other Power Supply Expense									
40		TOTAL PRODUCTION EXPENSE	(4,883,016)	-	-	(149,998)	-	-	-	-	469,110,645

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LINE NO.	FERC ACC'T	DESCRIPTION	(H) Adjustment 7 Overhaul and Outage	(I) Adjustment 8 Injuries and Damages	(J) Adjustment 9 Officers and Directors Ins.	(K) Adjustment 10 Lime Expense	(L) Adjustment 11 Rate Case Expense	(M) Adjustment 13 Property Tax Expense	(N) Adjustment 12 Miscellaneous and General	(O) Adjustment 14 Income Tax Expense	(P) RUCO AS ADJUSTED
41											
42		**Transmission Non-EHV (138 KV & Below)**									
43	560	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	561 & 561.1 - 561.8	Load Dispatch & Various	-	-	-	-	-	-	-	-	-
45	562	Station Expenses	-	-	-	-	-	-	-	-	-
46	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-
47	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-
48	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-
49	569 & 569.1-569.3	Maint. of Structures & Computers (Hard & Software & Equip	-	-	-	-	-	-	-	-	-
50	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-
51	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-
52	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-
53		**Total Transmission Non EHV (138 KN & Below)**			-						-
54		**Transmission EHV (345kv & Above) Expense**									
55	560	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	561 & 561.1 - 561.8	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-
57	562	Station Expenses	-	-	-	-	-	-	-	-	-
58	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-
59	565	Transmission of Electricity by Others - PPFAC Eligible	-	-	-	-	-	-	-	-	90,028,056
60	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-
61	567	Rents	-	-	-	-	-	-	-	-	-
62	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-
63	569 & 569.1 - 569.3	Maint. of Structures & Computers (Hard & Software & Equip	-	-	-	-	-	-	-	-	-
64	570	Maintenance of Station Equipment	-	-		-	-	-	-	-	-
65	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-
66	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-
67		**Total Transmission EHV (345kv & Above) Expense**			-						90,028,056
68											
69											
70											
71		**Distribution Expense**									
72	580	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,256,025
73	581	Load Dispatching	-	-	-	-	-	-	-	-	583,230
74	582	Station Expenses	-	-	-	-	-	-	-	-	228,882
75	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	619,711
76	584	Underground Line Expenses	-	-	-	-	-	-	-	-	138,526
77	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	172,210
78	586	Meter Expenses	-	-	-	-	-	-	-	-	2,264,374
79	587	Customer Installations Expense	-	-	-	-	-	-	-	-	132,788
80	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	9,521,762
81	589	Rents	-	-	-	-	-	-	-	-	867,282
82	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	768,136
83	591	Maintenance of Structures									
84	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	1,078,163
85	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	911,923
86	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	163,987
87	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	488,415
88	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-
89	597	Maintenance of Meters	-	-	-	-	-	-	-	-	113,856
90	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	220,737
91	407.3	Regulatory Asset Amortization	-	-	-	-	-	-	-	-	-
92		**Total Distribution Expense**	-	-	-	-	-	-	-	-	19,530,005

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Schedule RBM-8
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OPERATING INCOME – RUCO ADJUSTMENTS

LINE NO.	FERC ACC'T	DESCRIPTION	(H) Adjustment 7 Overhaul and Outage	(I) Adjustment 8 Injuries and Damages	(J) Adjustment 9 Officers and Directors Ins.	(K) Adjustment 10 Lime Expense	(L) Adjustment 11 Rate Case Expense	(M) Adjustment 13 Property Tax Expense	(N) Adjustment 12 Miscellaneous and General	(O) Adjustment 14 Income Tax Expense	(P) RUCO AS ADJUSTED
93		**Customer Account Expense**									
94	901	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
95	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	3,037,059
96	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	12,884,197
97	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	2,080,293
98	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-
99	908	Customer Assistance Expenses	-	-	-	-	-	-	-	-	948,015
100	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	120,864
101	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	14,638
102		**Total Customer Accounts Expense**	-	-	-	-	-	-	-	-	19,085,065
103		**Administrative and General Expense**									
104	920	Administrative & General Salaries	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	23,389,905
105	921	Office Supplies & Expenses	-	-	-	-	-	-	-	-	9,869,281
106	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	(10,853,685)
107	923	Outside Services Employed	-	-	-	-	-	-	-	-	9,837,609
108	924	Property Insurance	-	-	-	-	-	-	-	-	2,539,551
109	925	Injuries and Damages	-	-	(289,320)	-	-	-	-	-	2,695,835
110	926	Employee Pension & Benefits	-	-	-	-	-	-	-	-	20,664,271
111	928	Regulatory Commission Expenses	-	-	-	-	(346,667)	-	-	-	853,969
112	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	(301,307)
113	930.1	General Advertising Expenses	-	-	-	-	-	-	-	-	522,626
114	930.2	Miscellaneous General Expenses	-	-	-	-	-	-	(2,139,016)	-	1,979,936
115	931	Rents	-	-	-	-	-	-	-	-	332,450
116	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	50,310
117		**TotalAdministrative and General Expense**	-	-	(289,320)	-	(346,667)	-	(2,139,016)	-	61,580,751
118		**Total Operation and Maintenance Expense**	$ (4,883,016)	$ -	$ (289,320)	$ (149,998)	$ (346,667)	$ -	$ (2,139,016)	$ -	$ 659,334,523
119		**Depreciation & Amortization - All**									
120	403/404/406	Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	9,331,228
121	403/404/406	Other Production Plant	-	-	-	-	-	-	-	-	52,018,787
122	403/404/406	Transmission Plant	-	-	-	-	-	-	-	-	(26,365,701)
123	403/404/406	Distribution Plant	-	-	-	-	-	-	-	-	25,609,770
124	403/404/406	General Plant	-	-	-	-	-	-	-	-	10,350,629
125		**Total Depreciation & Amortization - All**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	70,944,713
126		**Taxes Other Than Income Taxes**									
127	408	Property Tax - Production	$ -	$ -	$ -	$ -	$ -	$ (1,418,488)	$ -		14,315,435
128	408	Property Tax - Other Production	-	-	-	-	-	-	-	-	-
129	408	Property Tax - Transmission (EHV & Non-EHV))	-	-	-	-	-	-	-	-	-
130	408	Property Tax - Distribution	-	-	-	-	-	$ (1,711,840)	-		11,347,212
131	408	Property Tax - General	-	-	-	-	-	$ 19,780	-		1,739,381
132	408	Business Activity Tax - Generation	-	-	-	-	-	-	-	-	4,272
133	408	*Business Activity Tax - Transmission*	-	-	-	-	-	-	-	-	-
134	408	Other (Including Payroll Taxes)	-	-	-	-	-	-	-	-	4,352,010
135		**Total Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ (3,110,547)	$ -	$ -	31,758,310
136											
137	431	Customer Deposit Interest Expense									45,852
138											
139	409	Current Income Tax - State & Federal								$ 22,525,476	29,543,844
140	410	Deferred IT - Federal & State (debits)									-
141	411	Deferred IT - Federal & State (credits)									-
142		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,525,476	$ 29,543,844
143		**Total Operating Expense**	$ (4,883,016)	$ -	$ (289,320)	$ (149,998)	$ (346,667)	$ (3,110,547)	$ (2,139,016)	$ 22,525,476	$ 791,627,242
		OPERATING INCOME (Test Year Adjusted)	$ 4,883,016	$ -	$ 289,320	$ 149,998	$ 346,667	$ 3,110,547	$ 2,139,016	$ (22,525,476)	$ 81,453,617

OPERATING EXPENSE ADJUSTMENT NO. 1
OTHER OPERATING INCOME

Line No.	Acct	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	451	Miscellaneous Service Income	$ 5,806,044	$ -	$ 5,806,044
2	454	Rent from Electric Property	23,259,549	6,961,004	30,220,553
3	456	Other Electric Revenues	116,375	-	116,375
4					
5		Total Other Operating Income	$ 29,181,968	$ 6,961,004	$ 36,142,972
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

References:
Column (A) Company Schedules
Column (B) Company Response to RUCO Data Request 8.04
Mr. DeConcici's Testimony Page 37 Lns 4 through 7

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OPERATING EXPENSE ADJUSTMENT NO. 2
DEPRECIATION / AMORTIZATION

Line No.	Acct	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Various	Total Depreciation Expense	$ 97,310,414	$ (26,365,701)	$ 70,944,713
2	407.3	Regulatory Asset Amortization	2,982,638	(2,982,638)	$ -
3					
4					
5		Total Other Operating Income	$ 100,293,052	$ (29,348,339)	$ 70,944,713
6					
7					
8					
9	Total Plant Depreciation Adjustments				
10		Depreciation adjustment due reduction in Gross Plant		$ 3,922,727	See RBM Sch 5-1
11		Depreciation adjustment related to removing office bldg.		1,885,760	See RBM Sch 5-2
12		Depreciation reduction due to return to ratepayers			
13		of excess depreciation reserve		20,557,214	FWR Testimony
14		Total Depreciation rduction		$ 26,365,701	
15					
16					
17					
18					
19					
20					
21					
22					
23	References:				
24		Column (A) Company Schedules			
		Column (B) RUCO Adjustments Total Depreciation Expense See Lns 10, 11, and 12			
		Column (B) RBM-5			
		Column (B) Company Schedules			

OPERATING EXPENSE ADJUSTMENT NO. 3
PAYROLL EXPENSE ADJUSTMENT

			(A)	(B)	(C)	(D)	(E)
1	FERC			ACC	Percentage	RUCO	RUCO
2	ACCT	ACCOUNT DESCRIPTION	Total Co	Jurisdictional	of Total	O&M Adj	O&M Final
3							
4	0500	Steam Prod Oper-Supervision	$ 321,629	$ 286,466	9.88%	$ 141,116	(145,350)
5	0501	Fuel - Steam	31,498	31,498	1.09%	15,516	(15,982)
6	0502	Steam Expenses	344,202	306,571	10.58%	151,020	(155,551)
7	0505	Electric Expenses	106,130	94,527	3.26%	46,565	(47,962)
8	0506	Steam Prod-Misc Expense	102,894	91,645	3.16%	45,145	(46,500)
9	0510	Maint-Supervision & Engr	126,723	112,868	3.89%	55,600	(57,268)
10	0511	Maint of Structures	29,484	26,261	0.91%	12,936	(13,325)
11	0512	Maint of Boiler Plant	283,575	266,129	9.18%	131,098	(135,031)
12	0513	Steam Prod-Mnt Elec Plnt	82,357	73,353	2.53%	36,134	(37,219)
13	0514	Steam Prod-Mnt Misc Plnt	107,457	95,709	3.30%	47,147	(48,562)
14	0546	Other Prod Oper-Supervision	1,603	1,428	0.05%	703	(725)
15	0549	Misc Other Pw Gen Exp	228	203	0.01%	100	(103)
16	0552	Maint of Structures	1,166	1,039	0.04%	512	(527)
17	0553	Maint Gen & Elec Plant	4,237	3,774	0.13%	1,859	(1,915)
18	0554	Maint of Misc Oth Pwr Gen Plant	1,019	908	0.03%	447	(461)
19	0556	Sys Cntrol/Load Dispatch	50,832	-	0.00%	-	-
20	0557	Prod Expense-Other	16,552	14,742	0.51%	7,262	(7,480)
21	0560	Trans-Oper Supv & Engr	36,366	-	0.00%	-	-
22	0561	Trans-Load Dispatch	51	-	0.00%	-	-
23	0566	Trans-Misc Oper Expense	2,695	-	0.00%	-	-
24	0568	Trans-Maint Supv & Engr	8,654	-	0.00%	-	-
25	0569	Trans-Maint of Structures	7	-	0.00%	-	-
26	0570	Trans-Maint Stn Equip	91,651	-	0.00%	-	-
27	0571	Trans-Maint of OH Lines	17,703	-	0.00%	-	-
28	0573	Trans-Maint Misc Trans Plnt	6	-	0.00%	-	-
29	0580	Dist-Oper Supv & Engr	35,603	35,603	1.23%	17,538	(18,065)
30	0581	Dist-Load Dispatching	18,929	18,929	0.65%	9,325	(9,604)
31	0582	Dist-Station Expenses	2,677	2,677	0.09%	1,319	(1,358)
32	0583	Dist-Overhead Line Exp	15,472	15,472	0.53%	7,622	(7,850)
33	0584	Dist-Underground Line Exp	5,450	5,450	0.19%	2,685	(2,765)
34	0585	Dist-Light/Signal Exp	198	198	0.01%	98	(100)
35	0586	Dist-Meter Expenses	44,665	44,665	1.54%	22,002	(22,663)
36	0587	Dist-Customer Install Exp	5,085	5,085	0.18%	2,505	(2,580)
37	0588	Dist-Misc Expense	139,011	139,011	4.80%	68,478	(70,533)
38	0590	Dist-Maint Supv & Engr	24,258	24,258	0.84%	11,950	(12,308)
39	0592	Dist-Maint Stn Equip	21,327	21,327	0.74%	10,506	(10,821)
40	0593	Dist-Maint of OH Lines	26,614	26,614	0.92%	13,110	(13,504)
41	0594	Dist-Maint of UG Lines	2,951	2,951	0.10%	1,454	(1,497)
42	0595	Dist-Mnt Line Transformers	11,513	11,513	0.40%	5,671	(5,842)
43	0597	Dist-Maint of Meters	4,433	4,433	0.15%	2,184	(2,249)
44	0598	Dist-Maint Misc Plant	2,084	2,084	0.07%	1,027	(1,057)
45	0903	Cust Rec/Collection Exp	284,937	284,937	9.83%	140,363	(144,574)
46	0908	Customer Assistance Exp	39,290	39,290	1.36%	19,355	(19,935)
47	0909	Informational/Instrct Adv Exp	1,305	1,305	0.05%	643	(662)
48	0920	A&G Salaries	800,149	707,727	24.42%	348,634	(359,093)
49	0925	Injuries & Damages	22,113	19,559	0.67%	9,635	(9,924)
50	0926	Pensions & Benefits	70,284	62,166	2.14%	30,624	(31,542)
51	0930	General Advertising Exp	18,350	16,230	0.56%	7,995	(8,235)
52	5611	Load Dispatch-Reliability	40,742	-	0.00%	-	-
53	5612	Load Dispatch-Monitor and Operation Tran:	41,400	-	0.00%	-	-
54	5613	Load Dispatch-Transmission Service and S	23,550	-	0.00%	-	-
55							
56		TOTALS	$ 3,471,110	$ 2,898,605	100%	$ 1,427,884	(1,470,721)

References
- Column (A) per Company calculated based on two years projected increases. See RBM-11 Page 2 of 2
- Column (B) per Company calculation of ACC Jurisdictional
- Column (C) Individual Account Compared to Total
- Column (D) See RBM-11 Page 2 of 2

OPERATING INCOME ADJUSTMENT NO. 3
PAYROLL EXPENSE ADJUSTMENT - CALCULATIONS

	(A) Total Payroll	(B) Clearing Acct Allo. to O&M	(C) UNS Chargebacks to TEP O&M	(D) Deduct SGS Unit 1 Disallowance	(E) Exclude A&G Payroll Capitalized Through A&G	(F) Deduct SGS Unit 3 Wages	(G) Deduct SGS Unit 4 Wages	(H) TOTAL O&M Wages
2010	$ 66,184,613	$ 10,580,705	$ 3,274,638	$ (5,447,068)	$ (6,022,809)	$ (6,381,524)	$ (6,780,351)	$ 55,408,205
2011	68,355,320	10,919,911	3,654,525	(6,013,389)	(4,911,883)	(6,286,501)	(7,132,454)	58,585,529
	134,539,934	21,500,616	6,929,163	(11,460,457)	(10,934,692)	(12,668,026)	(13,912,805)	113,993,733

2 Year Average O&M Wages		56,996,867
Average Wage Rate Increase	2012	3%
Wage increase at 3%		1,709,906
Adjusted 2 Year Average		58,706,773
Average Wage Rate Increase	2013	3%
		1,761,203
Total Payroll Adjustment - Per Company		$ 3,471,110

Total Company Payroll Adjustment	$ 3,471,110	Ln 21
Total TEP Payroll Adjustment ACC Jurisdiction	2,898,605	Per Company Schedule C-2
Percentage Allocated to TEP	83.51%	
Average Wage Increase per Company for 2012	1,709,906	Ln 13
Wage Increase for 2012 Related to TEP per RUCO	$ 1,427,884	Ln 32 * Ln 30
Adjustment Required Per RUCO	$ (1,470,721)	Ln 34 - Ln 28

References:
Columns (A) through (H) Lns 1 through 21 Provided by Company

OPERATING INCOME ADJUSTMENT NO. 4
INCENTIVE COMPENSATION

LINE NO.	ACCT NO.	DESCRIPTION	(A) COMPANY DISTRIBUTION OF INC COMP ADJ'MENT	(B) ALLOCATION FACTOR	(C) RUCO DISTRIBUTION OF INC COMP ADJ'MENT	(D) JURISDICTIONAL ALLOCATION	(E) RUCO ACC JURISDICTIONAL
1	500	Operation Supervision & Engineering - Gen.	$ 55,519	2.22%	$ (74,915)	89.07%	$ (66,725)
2	506	Miscellaneous Steam Power Expenses	520,332	20.82%	(702,116)	89.07%	(625,354)
3	566	Miscellaneous Transmission Expenses	388,687	15.55%	(524,479)	0.00%	-
4	588	Miscellaneous Distribution Expenses	142,306	5.69%	(192,022)	100.00%	(192,022)
5	903	Customer Records & Collection Expenses	149,804	5.99%	(202,140)	100.00%	(202,140)
6	920	Administrative & General Salaries	938,441	37.55%	(1,266,295)	88.45%	(1,120,032)
7	514	Maintenance Miscellaneous Steam Plant	205,015	8.20%	(276,639)	89.07%	(246,394)
8	570	Maintenance of Station Equipment	41,033	1.64%	(55,368)	0.00%	-
9	598	Maintenance of Miscellaneous Distribution Plant	22,502	0.90%	(30,363)	100.00%	(30,364)
10	580	Operation Supervision & Engineering - Dist.	35,269	1.41%	(47,591)	100.00%	(47,590)
11							
12		SUB-TOTALS	$ 2,498,908	100.00%	$ (3,371,928)		$ (2,530,620)
13							
14	408	FICA Taxes			$ (215,697)		$ (189,797)
15							
16					$ (3,587,625)		$ (2,720,417)

LINE NO.		REFERENCE	PAYROLL	FICA TAXES
17				
18	**NOTE:**			
19	RUCO Determination Of The Test-Year Incentive Compensation Payroll And FICA Taxes Expense Level:			
20				
21	STEP ONE: Restate Expense From 4-Year Average To Test Year Actual Level			
22		REFERENCE	PAYROLL	FICA TAXES
23	Adj. TY Level Of Payroll And FICA Taxes (3-Yr Average)	Company Workpapers	$ 6,247,890	$ 468,592
24	Actual Test-Year Level Of Payroll And FICA Taxes	Company Workpapers	$ 5,751,924	$ 431,394
25	RUCO Adjustment To Adhere To Historical TY Principle	Ln 23 - Ln 24	$ (495,966)	
26				
27	STEP TWO: Split Expense On A 50/50 Basis			
28	Company Test-Year Level Of Payroll And FICA Taxes	Company Workpapers	$ 5,751,924	$ 431,394
29	RUCO Adjustment To Split Expense On A 50/50 Basis	50% Of Line 28	$ (2,875,962)	$ (215,697)
30				
31	RUCO Adjusted Expense (See Col. (C), Lines 25 & 29)	Sum Lines 25 & 29	$ (3,371,928)	$ (215,697)
32				
33	RUCO Adjustment - Total Company		Sum Line 18, Col.'s (B) & (C)	$ (3,587,625)
34				
35	RUCO Adjustment - ACC Jurisdictional			$ (2,720,417)
36				
37				
38	References:			
39	Column (A): Company Workpapers			
40	Column (B): Individual Account Allocation Based On Percentage Of Each FERC Account To Total			
41	Column (C): RUCO Adjustment To Incentive Compensation Allocated By Computed Factors In Column (B)			

OPERATING EXPENSE ADJUSTMENT NO. 5
PAYROLL TAX EXPENSE

		(A)	(B)	(C)
1	**TEP Employer Tax - 2011**			
2	Social Security	$ 7,311,295	per Form 941	
3	Medicare	1,963,775	per Form 941	
4	FUTA/SUTA	206,758	per FUTA and SUTA returns	
5		9,481,829		
6				
7		Wages, tips and other compensation from Form 941		
8	1Q 2011	35,453,451		
9	2Q 2011	27,489,066		
10	3Q 2011	31,254,470		
11	4Q 2011	31,940,018		
12		126,137,006	0.075	Ln 5 / Ln 12
13				
14	Payroll Adjustment Per RUCO - RBM-12 Page 1		1,470,721	
15				
16	Employer Payroll Tax Adjustment per RUCO		$ 110,555	Ln 14 x Ln 12
17				
18	Employer Payroll Tax Adjustment per TEP		193,390	Company Schedule C-2
19				
20	Adjustment to Payroll Tax for Payroll Adjustments per RUCO		$ (82,835)	Ln 16 - Ln 18
21				
22				
23				
24	Payroll Tax Expense Adjustment - Payroll Adjustments		$ (82,835)	Per Above
25	Payroll Tax Expense Adjustment - Incentive Adjustment		$ (189,797)	See RBM-12 Ln E-14
26				
27	Total Payroll Tax Expense Adjustment		$ (272,631)	RUCO Adjustment
28				
29				
30	References:			
31	Columns (A through C) Lns 1 through 12 Company Workpapers			
32				

OPERATING INCOME ADJUSTMENT NO. 7
OVERHAUL AND OUTAGE

LINE NO.	Acct No.	DESCRIPTION	(A) TEP AS FILED	(B) RUCO RECOMMENDED	(B) ALLOCATION FACTOR	(C) RUCO AS ADJUSTED
2		Expenditures by Plant Location				
3		Four Corners				
4		Estimated recurring expense	$ 1,108,013	413,000		
5		Actual test year expenditures	1,012,000	1,012,000		
6		Adjustment	96,013	(599,000)	93.85%	$ (562,162)
8		Navajo				
9		Estimated recurring expense	2,133,721	1,244,000		
10		Actual test year expenditures	3,210,000	3,210,000		
11		Adjustment	(1,076,279)	(1,966,000)	93.85%	$ (1,845,091)
13		San Juan				
14		Estimated recurring expense	5,784,261	7,142,000		
15		Actual test year expenditures	6,667,000	6,667,000		
16		Adjustment	(882,739)	475,000	93.85%	$ 445,788
18		Luna				
19		Estimated recurring expense	591,308	1,026,000		
20		Actual test year expenditures	869,000	869,000		
21		Adjustment	(277,692)	157,000	93.85%	$ 147,345
23		Springerville Excluding #1				
24		Estimated recurring expense	2,779,583	-		
25		Actual test year expenditures	-	-		
26		Adjustment	2,779,583	-	93.85%	$ -
28		Sundt / Irvington				
29		Estimated recurring expense	2,631,115	-		
30		Actual test year expenditures	2,000,000	2,000,000		
31		Adjustment	631,115	(2,000,000)	93.85%	$ (1,877,000)
33		Net Estimated Recurring Expenses	15,028,001	9,825,000		
34		Net Test Year Expenditures	13,758,000	13,758,000		
36		COMPANY ADJUSTMENT	$ 1,270,001	$ (3,933,000)		(1,191,896)
38		RUCO ADJUSTMENT				
40		**RUCO ADJUSTMENT - ACC JURISDICTIONAL**				**$ (4,883,016)**

The Company calculated their estimated recurring expense utilizing seven years going forward average. Years included in their calculations were years 2012 thru 2018

RUCO included only the projected expenses for only year 2012. RUCO believes that this is the only known and measurable adjustment that should be made to the account.

References:
Column (A) Included in Company Workpapers
Column (B) Estimated recurring expense - See Data Response

Tucson Electric Power Company
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Test Year Ended December 31, 2011

OPERATING EXPENSE ADJUSTMENT NO. 8
INTENTIONALLY LEFT BLANK

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1				
2				
3				
4				
5				
6				
7				
8				
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10				
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16				
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21				
22				
23				
24				

Tucson Electric Power Company
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OPERATING EXPENSE ADJUSTMENT NO. 9
OFFICERS AND DIRECTORS INSURANCE

Line No.		DESCRIPTION		(A) COMPANY PROPOSED		(B) RUCO ADJUSTMENT		(C) RUCO AS ADJUSTED
1	925	Officers and Directors Liability Insurance	$	654,200	$	327,100	$	327,100
2								
3		TEP Allocation Percentage						88.45%
4								
5		Total RUCO Adjustment to ACC Jurisdictional	$	654,200	$	327,100	$	289,320
6								
7								
8								
9		Company Proposed	$	654,200				
10		Split between Ratepayers						
11		and Shareholders						
12		50 / 50	$	327,100				
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23		References:						
24		Column (A) See TEP Data Response 1.60 Insurance Expense						

TUCSON ELECTRIC POWER COMPANY
LIME EXPENSE
TEST YEAR ENDED DECEMBER 31, 2011

OPERATING INCOME ADJUSTMENT NO. 10
LIME EXPENSE

Ln		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M) Company	(N) RUCO
1	Actual data 2011	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	TOTALS	Recalculations
2	Lime Cost (product, freight, fuel surcharge, tax LESS add'l lime reimbursed to U12 from U34)	1,309,533	730,258	1,367,613	845,973	1,113,841	974,987	1,008,956	1,232,465	989,364	713,135	807,962	1,056,414	12,150,501	
3	Monthly lime cost per ton	128.59	129.29	129.38	129.38	129.38	129.38	130.10	133.84	134.16	134.16	134.16	134.16	131.33	
4	Sulfur Credit	-	(587,008)	(603,416)	(673,544)	(237,807)	(711,411)	(394,186)	(420,171)	(380,972)	(80,432)	(279,245)	(420,846)	(4,789,038)	
5	Gross Generation	550,674	524,974	495,553	539,275	574,309	466,649	586,914	557,653	531,105	301,505	413,735	559,704	6,102,050	
6	Net Lime (Lime cost less lime credit less add'l lime reimbursed from U3&4)	1,309,533	143,250	764,197	172,429	876,034	263,576	614,770	812,294	608,392	632,703	528,717	635,568	7,361,463	
7	Cost per MWh	2.38	0.27	1.54	0.32	1.53	0.56	1.05	1.46	1.15	2.10	1.28	1.14	1.21	
8															
9															
10															
11															
12															
13	Actual data 2012	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12		
14	Lime Cost (product, freight, fuel surcharge, tax LESS add'l lime reimbursed to U12 from U34)	634,048	1,935,884	1,374,806	1,233,063	1,193,982	1,413,620	1,016,163	1,270,043	1,016,552	713,135	807,962	1,056,414	11,088,160	13,665,671
15	Monthly lime cost per ton	136.13	140.83	140.58	140.58	140.58	141.42	141.42	143.90	143.74				141.02	141.02
16	Sulfur Credit	(453,821)	(317,250)	(337,746)	(477,949)	(329,199)	(285,429)	(355,276)	(2,925)	(449,680)	(80,432)	(279,245)	(420,846)	(3,009,275)	(3,789,798)
17	Gross Generation	564,728	554,055	558,005	520,258	573,361	508,455	569,382	598,828	498,909	301,505	413,735	559,704	4,945,981	6,220,925
18	Net Lime (Lime cost less lime sulfur credit)	180,227	1,618,634	1,037,060	755,114	864,783	1,128,191	660,887	1,267,118	566,872	632,703	528,717	635,568	8,078,885	9,875,873
19	Cost per MWh	0.32	2.92	1.86	1.45	1.51	2.22	1.16	2.12	1.14	-	-	-	1.63	1.59
20															
21		1,129,306	(1,475,384)	(272,863)	(582,685)	11,251	(864,615)	(46,117)	(454,824)	41,520	Actual 2012 increase over 2011		O8 / O21 -1	35.4%	31.6%
22															
23										2011 Lime Cost SGS Unit 2			M 7 X E27	3,942,464	3,942,464
24	Unit 1 Gross Production 2011				2,834,067	46%									
25	Unit 2 Gross Production 2011				3,267,977	54%				Increase to 2011 Test Year Cost - Ln 23 X Ln 25				1,395,534	1,245,536
26					6,102,044										
27															
28															
29										RUCO ADJUSTMENT TO LIME EXPENSE - Ln M25 - N25					$ 149,998

30 References:
31 Original Worksheet provided in Company Workpapers and updated per RUCO Date Response through Septenber 2012
32 October through December of 2012 estimates based on actual October through December 2011
33 RUCO Adjustments primarily due to Company's original estimate did not include sufficient Sulfer Credits
34
35
36
37
38

OPERATING INCOME ADJUSTMENT NO. 11
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense	$ 1,415,000	$ 915,000	$ 500,000
5	RUCO's Proposed Rate Case Expense:		$ 500,000	
9	RUCO's recommendation is based on two factors: (1) What has been approved in			
10	prior rate cases by the Commission; (2) What is fair and reasonable to the rate payer.			
13	RUCO Recommended Annual Amortization (4 years)			4
15	RUCO Recommended Annual Amortization (Ln 1 / Ln 13)			$ 125,000
17	TEP Rate Case Expense as Filed (Amortization Period 3 years)			$ 471,667
19	RUCO Pro Forma Rate Case Expense (Ln 15 - Ln 17)			$ (346,667)

Line No.	TEP Estimated Expenses	
25	Outside Counsel	$620,000
26	Depreciation Study	$365,000
27	Rate Design Study	$175,000
28	Tax Adjustment Study	$140,000
29	Cost of Equity Study	$115,000
31	Total Estimated Expense	$1,415,000

Tucson Electric Power Company
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Test Year Ended December 31, 2011

OPERATING INCOME ADJUSTMENT NO. 12
MISCELLANEOUS GENERAL EXPENSES

Line No.	CONTRIBUTIONS		(A) RUCO ADJUSTMENTS
1	Operating Expense of Corporate Building		$ 2,100,000
2	Charitable Contributions		39,016
3			
4			$ 2,139,016
5			
6			
7			
8	Charitable Contributions	$ 1,250	
9	United Way of Northern Arizona	6,714	
10	United Way of Tuscon and Southern Arizona	14,232	
11	Boys and Girls Club of Tuscon	950	
12	Charitable Contributions	3,060	
13	Charitable Contributions	1,000	
14	Society for Human Reso	165	
15	Charitable Contributions	240	
16	Charitable Contributions	1,500	
17	Thomas Alva Edison Foundation	15,000	
18			
19	TOTAL CONTRIBUTIONS IDENTIFIED	$ 44,111	
20			
21	ACC JURISDICTIONAL	88.45%	
22			
23	TOTAL RUCO ADJUSTMENT FOR CONTRIBUTIONS	$ 39,016	
24			
25			
26			
27			
28	Reference:		
29	Column (A) Ln 1 Sch RBM-5 page 2 Ln 1		
30	Ln 8 through Ln 17 - See response to RUCO Data Request 8.09		
31			
32			
33			
34			
35			
36			
37			

Tucson Electric Power Company
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OPERATING INCOME ADJUSTMENT NO. 13
PROPERTY TAX EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Property Tax Expense - Steam Production	$ 15,733,923	$ (1,418,488)	$ 14,315,435
2	Property Tax Expense - Distribution	13,054,052	$ (1,711,840)	11,342,212
3	Property Tax Expense - General	1,719,601	$ 19,780	1,739,381
4				
5	Total Property Tax Expense	$ 30,507,576	$ (3,110,547)	$ 27,397,029
6				
7				
8				
9				
10	**ADJUSTMENT TO EXPENSE**	Steam	Distribution	General
11				
12	Reduction in Plant in Service	$ 74,015,980	$ 88,165,340	$ -
13	Less: Accumulated Depreciation	(2,302,125)	(1,620,602)	(1,000,000)
14	Net Book Value	71,713,855	86,544,738	(1,000,000)
15				
16	Less: Assessment Ratio	19.50%	19.50%	19.50%
17				
18	Taxable Value	$ 13,984,202	$ 16,876,224	$ (195,000)
19				
20	Average Tax Rate	10.1435%	10.1435%	10.1435%
21				
22	Property Tax Reduction	$ 1,418,488	$ 1,711,840	$ (19,780)

References:

Column (A) Provided in Company Workpapers
Column (C) Ln 13 - RUCO's *reduction in property tax related to new office building*
Provided by Company. See Schedule RBM-5 Page 1
Column (A) and (B) Lns 12 and 13 See Schedule RBM-5

Tucson Electric Power Company
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Test Year Ended December 31, 2011

Schedule RBM-21
Page 1 of 1

OPERATING INCOME ADJUSTMENT NO. 14
INCOME TAX EXPENSE
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) REFERENCE		(B) AMOUNT
1	FEDERAL INCOME TAXES:			
2				
3	Operating Income Before Taxes	Schedule RBM-7, Column (C), Line 17 + Line 13	$	110,998
4	LESS:			
5	Arizona State Tax	Line 21		(5,208)
6	Interest Expense	Line 46		(36,257)
7	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$	69,533
8				
9	Federal Tax Rate	Schedule RBM-1, Page 2, Column (A), Line 12		35.00%
10	Federal Income Tax Expense	Line 4 X line 5	$	24,337
11				
12	STATE INCOME TAXES:			
13				
14	Operating Income Before Taxes	Line 3	$	110,998
15	LESS:			
16	Interest Expense	Line 21		(36,257)
17	State Taxable Income		$	74,741
18				
19	State Tax Rate	Tax Rate		6.97%
20				
21	State Income Tax Expense	Line 17 X Line 19	$	5,208
22				
23	TOTAL INCOME TAX EXPENSE:			
24				
25	Federal Income Tax Expense	Line 10	$	24,337
26	State Income Tax Expense	Line 21		5,208
27	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$	29,544
28	Total Income Tax Expense Per Company Filing (Schedule C-1)			7,019
29				
30	Difference	Line 27 - Line 28	$	22,525
31				
32	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RBM 7, Column (C), Line 13)	Line 30	$	22,525
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	NOTE (A):			
43	Interest Synchronization:			
44	Adjusted ACC Jurisdiction Rate Base (Schedule RBM-3, Column (D), Line 14)	$ 1,237,439		
45	Weighted Cost Of Debt (Schedule RBM-22, Column (F), Line 1 + Line 2)	2.93%		
46	Interest Expense (Line 18 X Line 19)	$ 36,257		

Tucson Electric Power Company
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COST OF CAPITAL - ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 10,000	$ -	$ 10,000	0.53%	1.42%	0.01%
2							
3	Long-term Debt	1,061,389	-	1,061,389	55.97%	5.22%	2.92%
4							
5	Common Equity	824,983	-	824,983	43.50%	10.00%	4.35%
6							
7	TOTAL CAPITAL	$ 1,896,372	$ -	$ 1,896,372	100.00%		
8							
9	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.28%
10							
11							

12 **COST OF CAPITAL - FAIR VAUE RATE BASE**

13							
14		(A)	(B)	(C)	(D)	(E)	(F)
15		COMPANY		RUCO			WEIGHTED
16		AS	RUCO	AS		COST	COST
17	DESCRIPTION	FILED	ADJUSTMENTS	ADJUSTED	PERCENT	RATE	RATE
18							
19	Short-term Debt	$ 10,000	$ -	$ 10,000	0.53%	1.42%	0.01%
20							
21	Long-term Debt	1,061,389	-	1,061,389	55.97%	3.03%	1.70%
22							
23	Common Equity	824,983	-	824,983	43.50%	7.81%	3.40%
24							
25	TOTAL CAPITAL	$ 1,896,372	$ -	$ 1,896,372	100.00%		
26							
27	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						5.11%
28							
29							

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) + Column (B)
Column (D): Column (C), Line Item / Total Capital
Column (E): Testimony, WAR
Column (F): Column (D) X Column (E)

EXHIBIT
RUCO-7

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

SUPPLEMENTAL DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

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SUPPLEMENTAL DIRECT TESTIMONY ON REVENUE REQUIREMENTS AND ENERGY EFFICIENCY RESOURCE PLAN

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REVISED REVENUE SCHEDULES (See Table of Contents to RUCO Final Revised Schedules Attached)

ENERGY EFFICIENCY RESOURCE PLAN (See Table of Contents for Energy Efficiency Resource Plan)

EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP" or "Company") is a Class A public utility and is a wholly owned operating subsidiary of UNS Energy Corporation. TEP is an electric utility serving approximately 404,000 retail customers in the Tucson metropolitan area of Pima County as well as parts of Cochise County. TEP also sells electricity to other utilities and power marketing entities in the western United States.

On July 2, 2012, the Company filed a general rate application requesting a revenue increase of $127.8 million or approximately a 15.3 percent increase over test year adjusted revenues of $837 million. The average residential customer would see their monthly bill increase from $85.17 to $95.82, a monthly increase of $10.65. RUCO is recommending a revenue increase of $46.4 million, an increase of 5.5 percent over test year revenues.

The Company is also proposing an Original Cost Rate Base (OCRB) of $1,519,073 and a Rate of Return of 8.52% while RUCO is proposing an OCRB of $1,321,544 and a Rate of Return of 7.28%.

In addition to an increase in rates for all classes of TEP's customers the Company is also requesting modifications to its Purchase Power and Fuel Adjustment Clause (PPFAC) and a modified approach to funding the cost of its energy efficiency (EE) and demand side management (DSM) programs. The Company is also seeking to establish a lost fixed cost recovery program related to energy efficiency and renewable generation requirements and an environmental cost recovery mechanism.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is Robert B. Mease. I am the Associate Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on December 21, 2012, I filed direct testimony presenting RUCO's required revenue recommendations for TEP.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's revised required revenue recommendations based on the findings of RUCO consultants Frank Radigan and Paul Goetz. I will also present RUCO's recommendations on the Company-proposed energy efficiency plan and RUCO's recommended rate design.

As described in Mr. Radigan's testimony filed on December 21, 2012, the Company failed to justify the increase in plant in service since the last rate case and Mr. Radigan recommended that gross utility plant in service be reduced by approximately $230.1 million and test year depreciation expense by approximately $26.3 million. It was further stated that RUCO leaves open the possibility to revise this adjustment to plant in service when it files its direct testimony on rate design on January 11, 2013 if it receives acceptable supporting documentation from the Company. The Company has provided additional information and RUCO is now recommending that plant in service be reduced by $138.6 million and depreciation expense be reduced by $23.7 million. Based on the information provided RUCO has made adjustments to its original schedules filed and has revised its testimony accordingly. The revisions to plant and related accounts are discussed on pages 2 through 7.

In addition, as discussed in Mr. Mease's testimony, the Energy Efficiency Resource Plan ("EERP") was to be discussed in testimony submitted with the rate design being filed on January 11, 2013. See RUCO's discussion on TEP's Energy Efficiency Resource Plan on pages 1 through 22 at the end of this document.

RATE BASE ADJUSTMENT SUMMARY

Rate Base Adjustment No. 1 – Gross Utility Plant in Service

RUCO is recommending reduction of Gross Utility Plant in Service by $138,614,227 as explained in the direct testimony of RUCO consultant, Frank Radigan.

Rate Base Adjustment No. 2 – Accumulated Depreciation

As explained in the direct testimony of RUCO consultant, Frank Radigan, RUCO is recommending reducing the Accumulated Depreciation Account by $126,516,244.

Rate Base Adjustment No. 6 – Allowance For Working Capital

Cash Working Capital should be decreased by $4,507,000 based on adjustments to various operating expense accounts.

OPERATING INCOME ADJUSTMENT SUMMARY

Operating Income Adjustment No. 2. – Depreciation Expense

RUCO is recommending a reduction in test year depreciation expense by $23,731,458. RUCO consultant Frank Radigan will provide testimony on this adjustment.

Operating Income Adjustment No. 13 – Property Tax Expense

An adjustment to property tax expense, of $1,352,038 is being proposed by RUCO due to the proposed reduction in the Company's rate base.

Operating Income Adjustment No. 14 – Income Tax Adjustment

RUCO is proposing that current year's income tax expense be increased by $17,513,996.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and identify RUCO's recommended revenue increase, operating income requirement as well as the Company's Original Cost Rate Base (OCRB) and Fair Value Rate Base (FVRB).

A. RUCO is recommending a revenue increase as follows:

000's	TEP	RUCO	DIFF.
Increase in gross revenue	$127,765	$ 46,370	($ 81,395)
Increase in revenues required	15.27%	5.54%	(9.73%)

RUCO is recommending operating income levels as follows:

000's	TEP	RUCO	DIFF.
Required operating income	$129,484	$104,229	($ 25,255)

RUCO is recommending OCRB and FVRB as follows:

000's	TEP	RUCO	DIFF.
Original Cost Rate Base	$1,519,073	$1,321,544	($ 197,529)
Fair Value Rate Base	$2,280,216	$2,039,707	($ 240,509)

RATE BASE

Rate Base Adjustment No. 1 – Gross Utility Plant in Service

Q. Can you please explain RUCO's proposed adjustment to Gross Utility Plant in Service?

A. RUCO is recommending reduction of Gross Utility Plant in Service by $138,614,237 based on the recommendation of RUCO consultant Frank Radigan.

Rate Base Adjustment No. 2 – Accumulated Depreciation

Q. What adjustments has RUCO recommended to the Company's Accumulation Depreciation accounts?

A. Based on the recommendation of RUCO consultant, Frank Radigan, RUCO is recommending reducing the Accumulated Depreciation Account by $126,516,244.

Rate Base Adjustment No. 6 – Cash Working Capital

Q. Please explain RUCO's adjustment to Cash Working Capital.

A. RUCO is recommending a Cash Working Capital decrease of $4,507,000. The adjustment is the result of RUCO's proposed expense reductions.

OPERATING INCOME

Operating Income Adjustment No. 2. – Depreciation Expense

Q. Can you please explain your adjustment to depreciation expense?

A. RUCO is recommending a reduction in test year depreciation expense by $23,731,458 as explained by Mr. Radigan in his testimony.

Operating Income Adjustment No. 12 – Miscellaneous General Expense

Q. What adjustment is RUCO proposing for miscellaneous expense expenses?

A. RUCO is recommending an additional test year expense of $5,820,875 based on Mr. Radigan's adjustment for market based rents applicable to commercial property.

Operating Income Adjustment No. 13 – Property Tax Expense

Q. Does RUCO accept the Company's methodology in calculating property tax expense?

A. Yes. The method used by the TEP in this rate case is consistent with prior cases as filed and has been accepted by RUCO.

Q. Why is RUCO making an adjustment to the Company's property taxes as filed?

A. RUCO is proposing a reduction in gross plant in service by $138,614,237, as discussed in Rate Base Adjustment No. 1. As a consequence of excluding plant from rate base the property taxes associated with the proposed reduction in plant is also reduced. The reduction in allowable property taxes based on the recalculated expense is $1,352,038.

Operating Income Adjustment No. 14 – Income Tax Expense

Q. Has RUCO made an adjustment to Income Tax Expense as filed by the Company?

A. Yes. RUCO has adjusted this expense based upon the methodology that is used in all rate applications reviewed by RUCO.

Q. Can you explain the method utilized in calculating income tax expense both for the test year adjustment as well as the method used in calculating the tax effects of proposed revenue adjustments?

A. When calculating income tax expense for rate making purposes RUCO begins with operating income before taxes and from that amount will deduct Arizona income taxes due and interest synchronization. (Interest synchronization is calculated as follows: Adjusted ACC Jurisdictional Rate Base X Weighted Cost of Debt). The two results, Arizona income taxes and interest synchronization, are multiplied by the statutory Federal Income Tax Rate. In this case RUCO has used 35 percent as the statutory Federal Income Tax Rate.

Q. When applying this methodology to the RUCO's proposed test year operating income what was the result?

A. There was an additional income tax expense proposed by RUCO of $17,513,996 and added to the Company's operating expenses.

Q. Was there an adjustment to income tax expense after RUCO's final revenue requirement was determined in this rate filing?

A. Yes. The increase in income tax expense related to RUCO's additional revenue requirement is $18,392,609.

Q. Does this conclude your testimony?

A. Yes.

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

REVISED

TABLE OF CONTENTS TO RUCO FINAL SCHEDULES

SCH. NO.	PAGE NO.	TITLE	
RBM-1	1 of 2	REVENUE REQUIREMENT ACC JURISDICTIONAL	**REVISED**
	2 of 2	GROSS REVENUECONVERSION FACTOR	**REVISED**
RBM-2	1	FAIR VALUE RATE BASE - ACC JURISDICTIONAL	**REVISED**
RBM-3	1 of 3	ORIGINAL COST RATE BASE - ACC JURISDICTIONAL	**REVISED**
	2 of 3	SUMMARY ORIGINAL COST RATE BASE - RUCO ADJUSTMENTS	**REVISED**
	3 of 3	SUMMARY ORIGINAL COST RATE BASE - COMPANY ADJUSTMENTS	
RBM-4	1	RATE BASE ADJUSTMENT NO. 1 - GROSS UTILITY PLANT IN SERVICE	**REVISED**
	2	RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEPRECIATION	**REVISED**
	3	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES (ADIT)	
	4	RATE BASE ADJUSTMENT NO. 4- REGULATORY LIABILITIES	
	5	RATE BASE ADJUSTMENT NO. 5 - REGULATORY ASSET (NOGALES TRANSMISSION LINE)	
	6	RATE BASE ADJUSTMENT NO. 6 - ALLOWANCE FOR WORKING CAPITAL	**REVISED**
RBM-5	1	TEST YEAR PLANT ADJUSTMENTS - RUCO ADJUSTMENTS	**REVISED**
	2	BUILDING COSTS ALLOCATED TO AFFILIATES	
RBM-6		ALLOWANCE FOR WORKING CAPITAL - LEAD / LAG STUDY	**REVISED**
RBM-7		OPERATING INCOME STATEMENT	**REVISED**
RBM-8	1 - 6	OPERATING INCOME - RUCO ADJUSTMENTS	
RBM-9		OPERATING INCOME ADJUSTMENT NO. 1 - OTHER OPERATING INCOME (SPRINGERVILLE)	
RBM-10		OPERATING INCOME ADJUSTMENT NO. 2 - DEPRECIATION EXPENSE	**REVISED**
RBM-11	1 & 2	OPERATING INCOME ADJUSTMENT NO. 3 - PAYROLL EXPENSE	
RBM-12		OPERATING INCOME ADJUSTMENT NO. 4 - INCENTIVE ADJUSTMENT	
RBM-13		OPERATING INCOME ADJUSTMENT NO. 5 - PAYROLL TAX EXPENSE ADJUSTMENT	
RBM-14		OPERATING INCOME ADJUSTMENT NO. 7 - OVERHAULS AND OUTAGE	
RBM-15		INTENTIONALLY LEFT BLANK	
RBM-16		OPERATING INCOME ADJUSTMENT NO. 9 - OFFICERS AND DIRECTORS INSURANCE	
RBM-17		OPERATING INCOME ADJUSTMENT NO. 10 - LIME EXPENSE	
RBM-18		OPERATING INCOME ADJUSTMENT NO. 11 - RATE CASE EXPENSE	
RBM-19		OPERATING INCOME ADJUSTMENT NO. 12 - MISCELLANEOUS GENERAL EXPENSE	**REVISED**
RBM-20		OPERATING INCOME ADJUSTMENT NO. 13 - PROPERTY TAX EXPENSE	**REVISED**
RBM-21		OPERATING INCOME ADJUSTMENT NO. 14 - INCOME TAX EXPENSE	**REVISED**
RBM-22		COST OF CAPITAL	

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REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,519,073	$ 3,041,359	$ 2,280,216	$ 1,321,544	$ 2,757,869	$ 2,039,707
2							
3	Adjusted Operating Income (Loss)	$ 52,471	$ 52,471	$ 52,471	$ 76,251	$ 76,251	$ 76,251
4							
5	Current Rate Of Return (Line 3 / Line 1)	3.45%	1.73%	2.30%	5.77%	2.76%	3.74%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 129,484	$ 129,484	$ 129,484	$ 104,229	$ 104,229	$ 104,229
8							
9	Weighted Average Cost of Capital	7.74%	7.74%	7.74%	7.28%	7.28%	7.28%
10							
11	Fair Value Adjustment	0.78%	-3.48%	-2.06%	0.61%	-3.50%	-2.17%
12							
13	Required Rate of Return	8.52%	4.26%	5.68%	7.89%	3.78%	5.11%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 77,013	$ 77,013	$ 77,013	$ 27,978	$ 27,978	$ 27,978
16							
17	Gross Revenue Conversion Factor (Schedule RBM-1, page 2)	1.6590	1.6590	1.6590	1.6574	1.6574	1.6574
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 127,765	$ 127,765	$ 127,765	$ 46,370	$ 46,370	$ 46,370
20							
21	Adjusted Test Year Revenue	$ 836,938	$ 836,938	$ 836,938	$ 836,938	$ 836,938	$ 836,938
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 964,703	$ 964,703	$ 964,703	$ 883,308	$ 883,308	$ 883,308
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	15.27%	15.27%	15.27%	5.54%	5.54%	5.54%
26							
27	Rate Of Return On Common Equity	10.75%	10.75%	10.75%	10.00%	10.00%	10.00%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules RBM-1, Page 2, RBM-2, RBM-7 and RBM-22
Column (E): Schedule RBM-2, Column (F)
Column (F): Average of Column (D) + Column (E)

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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		100.00%
2	Less: Uncollectibles	Per Company Workpapers	0.25%
3	Subtotal	Line 1 - Line 2	99.75%
4	Less: Combined Federal And State Tax Rate	Line 16	39.42%
5	Subtotal	Line 3 - Line 4	60.34%
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6574**
7			
8	CALCULATION OF EFFECTIVE TAX RATE:		
9	Arizona Taxable Income		100.0%
10	Arizona State Income Tax Rate		6.968%
11	Federal Taxable Income	Line 9 - Line 10	93.0%
12	Applicable Federal Income Tax Rate		35.0%
13	Effective Federal Income Tax Rate	Line 11 X Line 12	32.5%
14	Subtotal	Line 10 + Line 13	39.5%
15	Revenue Less Uncollectibles	Line 3	99.8%
16	Combined Federal And State Income Tax Rate	Line 14 X Line 15	39.4%
17			
18			
19			
20			
21			
22	Operating Income Deficiency	Sch RBM-1 Ln 15	$ 27,978
23	Gross Income Conversion Fzctor	Column (A) Ln 6	1.6574
24	Increase in Gross Revenue		$ 46,370
25			
26	Increase in Income Tax Expense	Ln 24 - Ln 22	$ 18,393
27			
28			

$ 18,392.609

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FAIR VALUE RATE BASE
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 3,199,453	$ 6,655,502	$ 4,927,478	208.02%	$ 3,060,840	$ 6,367,159	$ 4,713,999
2	Accumulated Depreciation	(1,411,639)	(3,005,492)	(2,208,566)	212.91%	(1,285,123)	(2,736,129)	(2,010,626)
3	Net Utility Plant In Service	$ 1,787,814	$ 3,650,010	$ 2,718,912		$ 1,775,717	$ 3,631,030	$ 2,703,373
4								
5	Plant Held For Future Use	$ -	$ -	$ -	100.00%	$ -	$ -	$ -
6								
7	Total Net Utility Plant	$ 1,787,814	$ 3,650,010	$ 2,718,912		$ 1,775,717	$ 3,631,030	$ 2,703,373
8								
9	Deductions:							
10	Cust. Advances For Const.	$ (8,924)	$ (13,182)	$ (11,053)	147.71%	$ (8,924)	$ (13,182)	$ (11,053)
11	Customer Deposits	(23,743)	(23,743)	(23,743)	100.00%	(23,743)	(23,743)	(23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(15,832)	(15,773)	(15,803)	99.63%	(15,832)	(15,773)	(15,803)
13	Acc. Deferred Income Taxes	(284,654)	(620,365)	(452,510)	217.94%	(351,705)	(766,494)	(559,100)
14	Total Deductions	$ (333,153)	$ (673,063)	$ (503,108)		$ (400,204)	$ (819,192)	$ (609,698)
15								
16	Allowance - Working Capital	$ 53,323	$ 53,323	$ 53,323	100.00%	$ 48,816	$ 48,816	$ 48,816
17								
18	Regulatory Assets	$ 11,089	$ 11,089	$ 11,089	100.00%	$ -	$ -	$ -
19								
20	Regulatory Liability	$ -	$ -	$ -	100.00%	$ (102,785)	$ (102,785)	$ (102,785)
21								
22								
23	**TOTAL TEST YEAR RATE BASE**	$ 1,519,073	$ 3,041,359	$ 2,280,216		$ 1,321,544	$ 2,757,869	$ 2,039,707

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule RBM-3 page 1, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F)

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 3,199,454	$ (138,614)	$ 3,060,840
2	Accumulated Depreciation	(1,411,639)	126,516	(1,285,123)
3	Net Utility Plant In Service	$ 1,787,815	$ (12,098)	$ 1,775,717
4				
5	Plant Held For Future Use	$ -	$ -	$ -
6				
7	Total Net Utility Plant	$ 1,787,815 0	$ (12,098)	$ 1,775,717
8				
9	Deductions:			
10	Cust. Advances For Const.	$ (8,924)	$ -	$ (8,924)
11	Customer Deposits	(23,743)	-	(23,743)
12	Def'd Credit - Cont'd Plt & Retm't Oblig.	(15,832)	-	(15,832)
13	Acc. Deferred Income Taxes	(284,654)	(67,051)	(351,705)
14	Total Deductions	$ (333,153)	$ (67,051)	$ (400,204)
15				
16	Allowance - Working Capital	$ 53,323	$ (4,507)	$ 48,816
17				
18	Regulatory Assets	$ 11,089	$ (11,089)	$ -
19				
20	Regulatory Liability	$ -	$ (102,785)	$ (102,785)
21				
22				
23	TOTAL OCRB	$ 1,519,074	$ (197,530)	$ 1,321,544

References:

Column (A): - Company Schedule B-2. Also see RBM-3 page 2 Col. A
Column (B): - RUCO Adjustments (See RBM-3 page 2, Columns (B) thru (G))
Column (C): - Sum Of Columns (A) and (B)

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SUMMARY ORIGINAL COST RATE BASE - RUCO ADJUSTMENTS
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) Adjustment No. 1 Gross Utility Plant	(C) Adjustment No. 2 Accumulated Depreciation	(D) Adjustment No.3 Accu Deferred Income Taxes	(E) Adjustment No.4 Regulatory Liabilities	(F) Adjustment No.5 Sahuarita-Nogales Trans. Line	(G) Adjustment No. 5	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 3,199,454	$ (138,614)	-		$ -	$ -	$ -	$ 3,060,840
2	Accumulated Depreciation	(1,411,639)	-	126,516	-	-	-	-	(1,285,123)
3	Net Utility Plant In Service	$ 1,787,815	$ (138,614)	$ 126,516	$ -	$ -	$ -	$ -	$ 1,775,717
4									
5	Plant Held For Future Use	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6									
7	Total Net Utility Plant	$ 1,787,815 0	$ (138,614)	$ 126,516	$ -	$ -	$ -	$ -	$ 1,775,717
8									
9	Deductions:								
10	Cust. Advances For Const.	$ (8,924)	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,924)
11	Customer Deposits	(23,743)	-	-	-	-	-	-	(23,743)
12	Def'd Credit - Plt & Retm't	(15,832)	-	-	-	-	-	-	(15,832)
13	Acc. Deferred Income Taxes	(284,654)	-	-	(67,051)	-	-	-	(351,705)
14	Total Deductions	$ (333,153)	$ -	$ -	$ (67,051)	$ -	$ -	$ -	$ (400,204)
15									
16	Allowance - Working Capital	$ 53,323	$ -	$ -	$ -	$ -	$ -	$ (4,507)	$ 48,816
17									
18	Regulatory Assets	$ 11,089	$ -	$ -			$ (11,089)	$ -	$ -
19									
20	Regulatory Liability	$ -	$ -	$ -	$ -	$ (102,785)	$ -	$ -	$ (102,785)
21									
22									
23	TOTAL OCRB	$ 1,519,074	$ (138,614)	$ 126,516	$ (67,051)	$ (102,785)	$ (11,089)	$ (4,507)	$ 1,321,544

References:
Column (A): Company Schedule B-1
Columns (B) Thru (G): RUCO Rate Base Adjustment Nos. 1 thru 5
Column (H): Sum Of Columns (A) Through (G)

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RATE BASE ADJUSTMENT NO. 1
GROSS UTILITY PLANT IN SERVICE
(Thousands of Dollars)

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Gross Utility Plant in Service	$ 3,199,454	$ (138,614)	3,060,840
2				
3				
4				
5				
6				
7				
8	Gross Utility Plant Reduction	$ 70,642,900	See RBM-5 page 1 Ln 44	
9			and FWR Testimony	
10	ACC Jurisdictional Costs of New Building	67,971,337		
11				
12	TOTAL ADJUSTMENTS	$ 138,614,237		
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23	References:			
24	Column (A) Ln 1 - Company Workpapers			
	Column (A) Ln 10 - Company Response to Staff Data Request 23.6			

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RATE BASE ADJUSTMENT NO. 2
ACCUMULATED DEPRECIATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Accumulated Depreciation	$ (1,411,638,679)	$ 126,516,244	$ (1,285,122,435)
11	RUCO Proposed Adjustments			
13	Reduction of A/D due to disallowance of plant in service		$ -	RBM-5 page 1, Ln 44
14	Reduction of A/D due to depreciation expense increase			
15	resulting from reclassification of plant		1,288,484	RBM-5 page 1, Ln 36
16	Reduction of A/D due to disallowance of new office building		1,885,760	RBM-5 page 2, Ln 17
17	Reduction of A/D due to the return of depreciation			
18	reserve to ratepayers		20,557,214	RBM-4 page 4, Ln 10
19	Reclassification of A/D to Regulatory Liability			
20	($123,342,000 - $20,557,000)		102,784,786	RBM-4 page 4, Ln 8
23			$ 126,516,244	

References:
Comumn (A) Company Schedule B-1

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RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	REFERENCE		(A) AMOUNT
1	Cash Working Capital Per TEP	TEP SCH. B-5, Page 1	$	(19,359)
2	Cash Working Capital Per RUCO	RBM-6		(23,866)
3	Adjustment	Line 2 - Line 1	$	(4,507)
4				
5	Fuel Inventory Per TEP	TEP SCH. B-5, Page 1	$	25,307
6	Fuel Inventory Per RUCO	TEP SCH. B-5, Page 1		25,307
7	Adjustment	Line 6 - Line 5	$	-
8				
9	Materials And Supplies Per TEP	TEP SCH. B-5, Page 1	$	42,837
10	Materials And Supplies Per RUCO	TEP SCH. B-5, Page 1		42,837
11	Adjustment	Line 10 - Line 9	$	-
12				
13	Prepayments Per TEP	TEP SCH. B-5, Page 1	$	4,538
14	Prepayments Per RUCO	TEP SCH. B-5, Page 1		4,538
15	Adjustment	Line 14 - Line 13	$	-
16				
17	TOTAL ADJUSTMENT - WORKING CAPITAL	Sum Lines 3, 7, 11, 15)	$	(4,507)
18				
19				
20				
21				
22				

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TEST YEAR PLANT ADJUSTMENTS

	2006			2011				RUCO ADJUSTED 2011					DEPRECIATION EXPENSE			
Acct.	Gross Plant	Depre Reserve	Net Plant	Gross Plant	Depre Reserve	Net Plant	Depre Rate	Gross Plant	Depr Res on 2006 Balance	Growth in Reserve Balance	Total Depre Reserve	Net Plant	Prop Depre Rate	Depreciation Expense Company	Depreciation Expense RUCO	Difference
Steam Production Plant																
310	$ 4,603	$ 2,243	$ 2,360	$ 4,603	$ 3,874	$ 729	5.34%	$ 4,603	$ 3,874	$ -	$ 3,874	$ 729	1.58%	73	73	-
311	111,087	62,031	49,056	168,247	97,520	70,727	5.16%	168,247	97,520	-	97,520	70,727	2.32%	3,903	3,903	-
312	652,151	332,664	319,487	1,020,623	489,561	531,062	3.87%	1,020,623	489,561	-	489,561	531,062	3.03%	30,925	30,925	-
314	206,960	101,243	105,717	300,048	140,860	159,188	3.79%	300,048	140,860	-	140,860	159,188	3.67%	11,012	11,012	-
315	71,511	38,182	33,329	116,382	59,751	56,631	3.24%	116,382	59,751	-	59,751	56,631	3.66%	4,260	4,260	-
316	19,281	10,338	8,943	22,314	13,826	8,488	3.88%	22,314	13,826	-	13,826	8,488	2.73%	609	609	-
317	70	56	14	-		-		9	-	-	-				-	
	$ 1,065,663	$ 546,757	$ 518,906	$ 1,632,217	$ 805,392	$ 826,825		$ 1,632,226	$ 805,392	$ -	$ 805,392	$ 826,825		50,781	50,781	-
Distribution Plant																
360	$ 7,991	$ 2,895	$ 5,096	$ 8,018	$ 3,543	$ 4,475	1.43%	8,012	3,466	7	3,473	4,539	1.43%	115	115	(0)
361	6,282	1,745	4,537	11,107	2,122	8,985	1.63%	9,973	2,257	(12)	2,245	7,728	1.72%	191	172	(20)
362	95,451	63,750	31,701	138,343	42,910	95,433	1.46%	128,263	70,718	(2,503)	68,215	60,048	1.53%	2,117	1,962	(154)
364	112,985	80,761	32,224	159,393	51,948	107,445	1.63%	148,487	89,969	(3,422)	86,547	61,940	1.74%	2,773	2,584	(190)
365	106,758	59,379	47,379	152,686	55,045	97,641	1.47%	141,893	67,226	(1,096)	66,129	75,764	1.63%	2,489	2,313	(176)
366	49,342	15,411	33,931	53,276	23,337	29,939	1.42%	52,352	18,914	398	19,312	33,040	1.35%	719	707	(12)
367	213,374	46,664	166,710	268,486	104,292	164,194	1.89%	255,535	66,828	3,372	70,200	185,335	1.87%	5,021	4,779	(242)
368	77,837	35,429	42,408	103,782	47,865	55,917	1.84%	97,685	42,590	475	43,065	54,620	1.87%	1,941	1,827	(114)
368	125,291	44,936	80,355	164,679	71,693	92,986	2.52%	155,423	60,723	987	61,710	93,713	2.09%	3,442	3,248	(193)
369	12,050	4,425	7,625	15,071	5,414	9,657	1.62%	14,361	5,401	1	5,402	8,959	1.85%	279	266	(13)
369	79,968	38,184	41,784	98,682	33,223	65,459	1.50%	94,284	44,182	(986)	43,195	51,089	1.52%	1,500	1,433	(67)
370	32,881	11,285	21,596	45,714	14,857	30,857	2.99%	42,698	16,201	(121)	16,080	26,618	3.29%	1,504	1,405	(99)
373	9,334	5,835	3,499	11,173	4,814	6,359	1.74%	10,741	6,647	(165)	6,482	4,259	1.77%	198	190	(8)
374	216	183	33	-		-	0.00%	51	-							
	$ 929,760	$ 410,882	$ 518,878	$ 1,230,410	$ 461,063	$ 769,347		$ 1,159,758	$ 495,121	$ (3,065)	$ 492,056	$ 667,651		$ 22,288	$ 20,999	$ (1,288)
Total	$ 1,995,423	$ 957,639	$ 1,037,784	$ 2,862,627	$ 1,266,455	$ 1,596,172		$ 2,791,984	$ 1,300,513	$ (3,065)	$ 1,297,448	$ 1,494,476		$ 73,069	$ 71,780	$ (1,288)

ADJUSTMENT TO GROSS UTILITY PLANT

Steam Plant as Submitted by Company	$ 1,632,217
Steam Plant Recomputed by RUCO	$ 1,632,226
Decrease in Gross Value Steam Plant	$ (9)
Distribution Plant as Submitted by Company	$ 1,230,410
Distribution Plant Recomputed by RUCO	$ 1,159,758
Decrease in Gross Value Dist. Plant	$ 70,652
Total Reduction in Plant	$ 70,642,900

DEPRECIATION EXPENSE ADJUSTMENT

$ (1,288,484)

BUILDING COSTS ALLOCATED TO AFFILIATES

			(A)				
1	Investment in Land-downtown HQ	$	8,549,938				
2	Investment in Office Facilities		71,430,308				
3	Investment in Furniture & Equipment		50,023				
4	Less: Accumulated Depreciation		(901,025)				
5	Less: Accumulated Depreciation		(1,176,718)				
6	Less: Accumulated Deferred Income Taxes		-				
7	Net Investment in Office Facilities		77,952,526				
8	Multiplied by: Current Regulated Rate of Return		8.03%				
9							
10	Required Return on Office Facilities and F&E		6,259,588				
11							
12	Add:						
13	O&M Expenses Applicable to Office Facilities and F&E		2,100,000	RBM-19			
14	PC/Lan Expenses		-				
15	Property Taxes Applicable to Office Facilities		1,000,000	RBM-20			
16	Insurance Costs Applicable to Office Facilities		-				
17	Book Depreciation on Office Facilities		1,885,760	RBM-10			
18	Income Taxes on Equity Portion of Return **		2,225,597	Sq FT	$ per sq foot		Annual Revenue Requirment ($ millions)
19							
20	Revenue Requirement for Office Facilities and F&E		13,470,945	232,835	57.86	$	13,470,945
21							
22	Diveded by: Number of Employees - Excluding SPG		539		25.00	$	5,820,875
23							
24	Cost Per Employee	$	24,992	Calculated IncomeAffects of Bldg		$	(7,650,070)
25							
26	Divided by: Annual Labor Hrs.		2,080				
27							
28	Facilities Cost Per Hour	$	**12.02**				
29							
30	**						
31	Net Investment in Office Facilities	$	77,952,526				
32	Regulated Rate of Return - Equity Component		4.36%				
33	Equity Component of Return on Office Facilities		3,398,730				
34	Divide by 1- Combined Tax Rate		60.4291%				
35			5,624,327				
36	Multiply by Combined Tax Rate		39.5709%				
37	Income Taxes on Equity Portion of Return	$	2,225,597				
38							

References:
Company Data Response
See FWR Testimony

Tucson Electric Power Company
Docket No. E-01933A-12-0291 **REVISED** Schedule RBM-6
Test Year Ended December 31, 2011

ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requirements
	OPERATING EXPENSES					-	-	-	-
	Non-Cash Expenses:								
1	Bad Debts Expense	$ 2,080,293	$ (2,080,293)	-			-		$ -
2	Depreciation	119,580,496	$ (119,580,496)	-			-		-
3	Amortization	3,481,610	$ (3,481,610)	-			-		-
4	Deferred Income Taxes	12,803,088	$ (12,803,088)	-			-		-
5	Total Non-Cash Expenses	$ 137,945,487	$ (137,945,487)	$ -					$ -
	Other Operating Expenses:								
6	Salaries & Wages	$ 71,991,108	$ (1,470,721)	$ 70,520,387	36.47	10.46	26.01	7.13%	$ 5,025,302
7	Incentive Pay	6,247,890	(2,530,620)	3,717,270	36.47	259.50	(223.03)	-61.10%	(2,271,404)
8	Fuel Expense	285,386,416	-	285,386,416	36.47	29.50	6.97	1.91%	5,449,708
9	Lease Expense	101,812,888	-	101,812,888	36.47	94.33	(57.86)	-15.85%	(16,139,435)
10	Remote Generating Plant O & M	47,385,627	(4,883,016)	42,502,611	36.47	(6.90)	43.37	11.88%	5,050,242
11	Office Supplies and Expenses	9,594,745	-	9,594,745	36.47	12.46	24.01	6.58%	631,150
12	Outside Services	10,520,391	-	10,520,391	36.47	44.51	(8.04)	-2.20%	(231,737)
13	Property Insurance	2,271,746	(289,320)	1,982,426	36.47	-	36.47	9.99%	198,080
14	Injuries and Damages	2,278,506	-	2,278,506	36.47	(13.27)	49.74	13.63%	310,501
15	Pensions and Benefits	17,449,591	-	17,449,591	36.47	13.03	23.44	6.42%	1,120,598
16	Misc. General Expenses	4,285,497	3,681,859	7,967,356	36.47	(2.00)	38.47	10.54%	839,737
17	Rents	375,864	-	375,864	36.47	(40.51)	76.98	21.09%	79,271
18	Property Taxes	39,148,092	(1,352,038)	37,796,054	36.47	213.78	(177.31)	-48.58%	(18,360,598)
19	Payroll Taxes	7,830,466	$ (272,631)	7,557,835	36.47	16.53	19.94	5.46%	412,886
20	Current Income Taxes	7,016	22,763	29,779	36.47	62.05	(25.58)	-7.01%	(2,087)
21	Other Taxes	46,168	-	46,168	36.47	91.37	(54.90)	-15.04%	(6,944)
22	Interest on Customer Deposits	(2,439)	-	(2,439)	36.47	182.50	(146.03)	-40.01%	976
23	Other Operations and Maint.	63,312,707	(149,998)	63,162,709	36.47	11.99	24.48	6.71%	4,236,228
24	Total Other Operating Exp.	$ 669,942,279	$ (7,243,724)	$ 662,698,555					$ (13,657,527)
25									
26	Other Cash Working Capital Elements:								
27	Interest on Long-Term Debt	$ 54,838,713	$ -	54,838,713	36.47	86.20	(49.73)	-13.62%	$ (7,471,587)
28	Rev. Taxes and Assessments	85,440,494	-	85,440,494	36.47	48.16	(11.69)	-3.20%	$ (2,736,437)
29	Total Other Cash Working Cap.	$ 140,279,207	$ -	$ 140,279,207					$ (10,208,023)
30									
31	TOTAL CASH WORKING CAPITAL	$ 948,166,973		$ 802,977,762					$ (23,865,550)
32									
33									
34									
35									

36 References:
37 Column (A): - Company Schedule B-5
38 Column (B): RUCO Operating Income Adjustments (See RBM-8)
39 Column (C): Column (A) + (B)
40 Column (D): Company Schedule B-5, Page 3
41 Column (E): Column (C) X Column (D)

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

REVISED

Schedule RBM-7
Page 1

OPERATING INCOME STATEMENT
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D	(E) RUCO PROPOSED ACC JURID'L	(F) RUCO RECOM'D ACC JURID'L
1	Operating Revenues:					
2	Electric Retail Revenues	$ 836,938	$ -	$ 836,938	$ 46,370	$ 883,308
3	Sales for Resale	-	-	-		
4	Other Operating Revenue	$ 29,183	6,961	36,144	-	$ 36,144
5						
6	TOTAL OPERATING REVENUES	$ 866,121	$ 6,961	$ 873,082	$ 46,370	$ 919,452
7						
8	Operating Expenses:					
9	Fuel, Purchased Power and Trans	$ 292,188	(6,692)	$ 285,496		$ 285,496
10	Other Operations and Maintenance Exp	381,988	(2,286)	379,702		379,702
11	Depreciation and Amortization	97,311	(23,731)	73,580		73,580
12	Taxes Other than Income Taxes	35,142	(1,625)	33,517		33,517
13	Income Taxes	7,019	17,514	24,533	18,393	42,926
14	Rounding Differences	-	2	2		2
15	TOTAL OPERATING EXPENSES	$ 813,648	$ (16,817)	$ 796,831	$ 18,393	$ 815,223
16						
17	OPERATING INCOME (LOSS)	$ 52,473	$ 23,778	$ 76,251	$ 27,978	$ 104,229

References:
Column (A) Per Company Filing
Column (B) Schedule RBM-8
Column (E) Schedule RBM-1 page 2

References:
Column (A): Company Schedule C-1
Column (B): Testimonies, RLM & MDC And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Column (C) X Jurisdictional Factor
Column (E): See Schedule RLM-1
Column (F): Column (D) + Column (E)

Tucson Electric Power Company
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OPERATING EXPENSE ADJUSTMENT NO. 2
DEPRECIATION / AMORTIZATION

Line No.	Acct	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Various	Total Depreciation Expense	$ 97,310,414	$ (23,731,458)	$ 73,578,956
2	407.3	Regulatory Asset Amortization	2,982,638	(2,982,638)	$ -
3					
4					
5		Total Other Operating Income	$ 100,293,052	$ (26,714,096)	$ 73,578,956
6					
7					
8					
9	Total Plant Depreciation Adjustments				
10		Depreciation adjustment due reduction in Gross Plant		$ 1,288,484	See RBM Sch 5-1
11		Depreciation adjustment related to removing office bldg.		1,885,760	See RBM Sch 5-2
12		Depreciation reduction due to return to ratepayers			
13		of excess depreciation reserve		20,557,214	FWR Testimony
14		Total Depreciation rduction		$ 23,731,458	
15					
16					
17					
18					
19					
20					
21					
22					
23	References:				
24		Column (A) Company Schedules			
		Column (B) RUCO Adjustments Total Depreciation Expense See Lns 10, 11, and 12			
		Column (B) RBM-5			
		Column (B) Company Schedules			

REVISED

OPERATING INCOME ADJUSTMENT NO. 12
MISCELLANEOUS GENERAL EXPENSES

Line No.	CONTRIBUTIONS		(A) RUCO ADJUSTMENTS
1	Rental Expense Based on Marker Rates for Corporate Building		$ (5,820,875)
2	Operating Expense of Corporate Building		2,100,000
3	Charitable Contributions		39,016
4			
5			$ (3,681,859)
6			
7			
8	Charitable Contributions	$ 1,250	
9	United Way of Northern Arizona	6,714	
10	United Way of Tuscon and Southern Arizona	14,232	
11	Boys and Girls Club of Tuscon	950	
12	Charitable Contributions	3,060	
13	Charitable Contributions	1,000	
14	Society for Human Reso	165	
15	Charitable Contributions	240	
16	Charitable Contributions	1,500	
17	Thomas Alva Edison Foundation	15,000	
18			
19	TOTAL CONTRIBUTIONS IDENTIFIED	$ 44,111	
20			
21	ACC JURISDICTIONAL	88.45%	
22			
23	TOTAL RUCO ADJUSTMENT FOR CONTRIBUTIONS	$ 39,016	
24			
25			
26			
27			
28	Reference:		
29	Column (A) Ln 1 Sch RBM-5		
30	Column (A) Ln 2 Sch RBM-5 page 2 Ln 1		
31	Ln 8 through Ln 17 - See response to RUCO Data Request 8.09		
32			
33			
34			
35			
36			
37			

Tucson Electric Power Company
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OPERATING INCOME ADJUSTMENT NO. 13
PROPERTY TAX EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Property Tax Expense - Steam Production	$ 15,733,923	$ -	$ 15,733,923
2	Property Tax Expense - Distribution	13,054,052	$ (1,371,818)	11,682,234
3	Property Tax Expense - General	1,719,601	$ 19,780	1,739,381
4				
5	Total Property Tax Expense	$ 30,507,576	$ (1,352,038)	$ 29,155,538
6				
7				
8				
9				
10	**ADJUSTMENT TO EXPENSE**	Steam	Distribution	General
11				
12	Reduction in Plant in Service	$ -	$ 70,642,900	$ -
13	Less: Accumulated Depreciation	-	(1,288,484)	(1,000,000)
14	Net Book Value	-	69,354,416	(1,000,000)
15				
16	Less: Assessment Ratio	19.50%	19.50%	19.50%
17				
18	Taxable Value	$ -	$ 13,524,111	$ (195,000)
19				
20	Average Tax Rate	10.1435%	10.1435%	10.1435%
21				
22	Property Tax Reduction	$ -	$ 1,371,818	$ (19,780)

26 References:

28 Column (A) Provided in Company Workpapers
29 Column (C) Ln 13 - RUCO's reduction in property tax related to new office building
30 Provided by Company. See Schedule RBM-5 Page 1
31 Column (A) and (B) Lns 12 and 13 See Schedule RBM-5

Tucson Electric Power Company
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Test Year Ended December 31, 2011

OPERATING INCOME ADJUSTMENT NO. 14
INCOME TAX EXPENSE

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
1	FEDERAL INCOME TAXES:		
2			
3	Operating Income Before Taxes	Schedule RBM-7, Column (C), Line 17 + Line 13	$ 100,784
4	LESS:		
5	Arizona State Tax	Line 21	(4,325)
6	Interest Expense	Line 46	(38,721)
7	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 57,738
8			
9	Federal Tax Rate	Schedule RBM-1, Page 2, Column (A), Line 12	35.00%
10	Federal Income Tax Expense	Line 4 X line 5	$ 20,208
11			
12	STATE INCOME TAXES:		
13			
14	Operating Income Before Taxes	Line 3	$ 100,784
15	LESS:		
16	Interest Expense	Line 21	(38,721)
17	State Taxable Income		$ 62,063
18			
19	State Tax Rate	Tax Rate	6.97%
20			
21	State Income Tax Expense	Line 17 X Line 19	$ 4,325
22			
23	TOTAL INCOME TAX EXPENSE:		
24			
25	Federal Income Tax Expense	Line 10	$ 20,208
26	State Income Tax Expense	Line 21	4,325
27	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 24,533
28	Total Income Tax Expense Per Company Filing (Schedule C-1)		7,019
29			
30	Difference	Line 27 - Line 28	$ 17,514
31			
32	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RBM 7, Column (C), Line 13)	Line 30	$ 17,514
33			
34			
35			
36			
37			
38			
39			
40			
41			
42	NOTE (A):		
43	Interest Synchronization:		
44	Adjusted ACC Jurisdiction Rate Base (Schedule RBM-3, Column (D), Line 14)	$ 1,321,544	
45	Weighted Cost Of Debt (Schedule RBM-22, Column (F), Line 1 + Line 2)	2.93%	
46	Interest Expense (Line 18 X Line 19)	$ 38,721	

Tucson Electric Power Company
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Schedule RBM-20
Page 1 of 1

REVISED

OPERATING INCOME ADJUSTMENT NO. 13
PROPERTY TAX EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Property Tax Expense - Steam Production	$ 15,733,923	$ -	$ 15,733,923
2	Property Tax Expense - Distribution	13,054,052	$ (1,371,818)	11,682,234
3	Property Tax Expense - General	1,719,601	$ 19,780	1,739,381
4				
5	Total Property Tax Expense	$ 30,507,576	$ (1,352,038)	$ 29,155,538
6				
7				
8				
9				
10	**ADJUSTMENT TO EXPENSE**	Steam	Distribution	General
11				
12	Reduction in Plant in Service	$ -	$ 70,642,900	$ -
13	Less: Accumulated Depreciation	-	(1,288,484)	(1,000,000)
14	Net Book Value	-	69,354,416	(1,000,000)
15				
16	Less: Assessment Ratio	19.50%	19.50%	19.50%
17				
18	Taxable Value	$ -	$ 13,524,111	$ (195,000)
19				
20	Average Tax Rate	10.1435%	10.1435%	10.1435%
21				
22	Property Tax Reduction	$ -	$ 1,371,818	$ (19,780)

23
24
25
26 References:
27
28 Column (A) Provided in Company Workpapers
29 Column (C) Ln 13 - RUCO's reduction in property tax related to new office building
30 Provided by Company. See Schedule RBM-5 Page 1
31 Column (A) and (B) Lns 12 and 13 See Schedule RBM-5
32
33
34
35
36
37

EXHIBIT

RUCO-8

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON

ENERGY EFFICIENCY RESOURCE PLAN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

TABLE OF CONTENTS – ENERGY EFFICIENCY RESOURCE PLAN

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INTRODUCTION

REVIEW OF TEP 2012 EE IMPLENTATION PLAN DOCKET

Q. Before getting into the details of the EERP, please provide a quick review TEP's current Energy Efficiency Plan.

A. TEP recovers dollar-for-dollar the costs of energy efficiency programs through its Demand Side Management Surcharge ("DSMS"). The Commission set TEP's current DSMS rate of $0.00129 per kWh in Decision No. 71720. The DSMS surcharge rate went into effect June 1, 2010. Decision No. 71720 allowed TEP to recover: (1) its estimated 2010 EE program expenses; (2) a 2009 Performance Incentive; and (3) some under recovery of previous years' program costs.[1] The current DSMS surcharge collects approximately $11 million per year.

In January 2011, TEP filed an Application for approval of expanded EE programs. For numerous reasons, there was significant delay relating to this docket, and ultimately this matter was sent to hearing. At hearing, RUCO joined TEP and other intervenors and supported

[1] See Docket No. E-01933A-11-0055 Recommended Opinion and Order, FOF 31, p. 9

TEP's "Updated Plan".[2] This was a 15 month plan beginning October 2012 and ending December 2013 with the following details:

	Updated Plan Oct. 2012 – Dec. 2013
PROGRAM COST	$18,532,606
PERFORMANCE INCENTIVE	
2010	$1,114,648
2011	$1,101,749
2012	$3,283,854
UNDERCOLLECTED BALANCE Thru 2011	$3,862,556[3]
TOTAL	**$27,894,412**[4]

The Updated Plan proposed to increase the DSMS to $0.002497 per kWh from $0.00129 per kWh for residential customers which increased the average residential bill to $2.20 from $1.10.[5]

Q. **What is the status of the Updated Plan?**

A. The matter is ready for Commission review at an Open Meeting. The ALJ has issued a Recommended Order and Opinion recommending approval of the Updated Plan. However, it is likely that this matter will not be placed on an Open Meeting agenda in the near future – due, in part, that

[2] Staff opposed the Updated Plan.
[3] TEP originally identified an under recovered balance of $13,440,236 through 2011. However, TEP agreed to accept a reduced unrecovered balance amount of $3,862,556. At the time of hearing TEP identified its under collected bank balance at $6.5 million (ROO at p. 10, ftnte 27). However, RUCO understands that as of October 2012, the balance is $5.5 million.
[4] TEP also requested the creation of a lost fixed cost recovery mechanism (AART). Through discussions with other parties, TEP agreed to eliminate its request for the mechanism.
[5] See Docket No. E-01933A-11-0055 Recommended Order and Opinion, FOF 50, p. 16.

the 2012 Updated Plan was intended to serve as a "bridge" until the next rate case, which is now before us.

Q. How does TEP plan to recover any under collected DSMS balance going forward?

A. Footnotes 7 and 8 on page 66 of Craig Jones's Direct Testimony leads RUCO to believe that TEP anticipated the possibility of a balance and would recover it beginning in 2013.

Q. Does RUCO agree with TEP's claim that it has faced "challenges" in implementing its EE Programs?

A. RUCO understands TEP's frustrations. The Company filed its Application in January 2011. Yet, as 2012 draws to a close, TEP still has no Plan in place to meet the EE Standard. TEP has scaled back DSM/EE programs to fit within the revenues collected under the 2010 DSMS rate.

TEP has an admirable track record of making a good faith effort to meet the ACC Energy Efficiency Standard despite incurring a significant under collected balance. And, from public comment, it appears that TEP has the overwhelming support of the community to provide enhanced, cost effective EE programs. RUCO is very appreciative of TEP's willingness to address RUCO's concerns in the 2012 EE Plan docket and to find compromise in that matter.

RUCO OPPOSES TEP'S ENERGY EFFICIENCY RESOURCE PLAN AS FILED IN THE PENDING RATE CASE

Q. Does RUCO believe that TEP's proposed EERP is the best way to alleviate those challenges?

A. No. RUCO respectfully opposes TEP's proposal and finds it not to be in the best interest of ratepayers. Yet, RUCO understands the motivations behind the EERP and is willing to investigate other possibilities to reduce administrative delay, set affordable DSMS rates, and provide program level certainty to the utility, its customers, and DSM/EE contractors.

Q. Please describe the EERP.

A. In summary, TEP proposes the EERP as a "pilot program" to address the "challenges the Company has faced in implementing its EE programs". The EERP:

1. Establishes a 3-year Plan period commencing August 1, 2013.
2. Sets annual EE budgets as follows:

Year 1	$24,739,192
Year 2	$27,044,908
Year 3	$27,856,255

3. Capitalizes the program costs of the Plan and amortizes recovery over a four (4) year period.

4. Applies a Performance Incentive to the amount spent on EE calculated as the authorized Rate of Return plus a 200 basis point premium added to the cost of equity and recovers it over the same four (4) year period.

5. Creates a regulatory asset for recovery of the revenues spent on EE programs.

6. Authorizes TEP to select and administer DSM/EE programs it independently determines to be cost effective over the three years of the EERP consistent with the approved annual budgets.

7. Eliminates annual Commission review and approval of EE plans.

8. Includes a Plan of Administration that includes a Societal Cost Test Template that TEP would use to determine cost effectiveness.

Q. In summary, why does RUCO oppose the EERP?

A. RUCO opposes the EERP because it is not in the best interest of ratepayers for the following reasons:

1. By capitalizing program costs and applying carrying costs, the ratepayers may end up paying more for the EE programs than if these costs were expensed.

2. The rate of return plus 200 basis points premium that is applied to the DSM/EE program costs constitutes a performance incentive that is not based on actual performance and rewards spending over EE savings.

3. The 3 year term unnecessarily binds future Commissions to spending levels and program structure.
4. The EERP eliminates significant Commission oversight.
5. The EERP commits the ratepayers to pay $96.6 million over six (6) years for a three (3) year program without any detail on what programs or measures the Company will implement.

EERP MAY COST RATEPAYERS MORE IN THE LONG RUN

Q. Since rate impact is an important consideration for RUCO, why doesn't RUCO support a methodology that reduces the DSMS rate while still providing adequate revenue to TEP to meet the EE Standard?

A. According to TEP, the 3 year EERP program costs equal $79,640,355. However, over the amortization period, ratepayers will pay a total of $96,619,255.[6] This is $16,978,900 over the actual costs of the DSM/EE program. The carrying costs plus premium associated with capitalizing the EE program increases costs in the long run.

RUCO has consistently supported ***cost effective*** energy efficiency programs. With that said, RUCO has also recommended that any EE goal be aggressive yet realistic. RUCO notes TEP's concern that the EE

[6] Craig Jones, Direct Testimony at p. 65.

Standard may not be achievable or may be so costly that compliance is unfeasible.

> "While TEP supports the underlying principles, the Company has continuously asserted that the EES goals may not be reasonably achievable and, as such, may create unintended consequences for utilities and customers. For instance EES compliance costs increase significantly each year as utilities are required to meet ever increasing annual and cumulative savings goals. Cost will escalate further as utilities exhaust the potential of the simplest and most cost effective measures and are forced to invest in less productive and more expensive programs." (Hutchens Direct Testimony, p. 16.)

If meeting the EE Standard is not "reasonably achievable", then the solution is not to exacerbate the problem by making the program costs more expensive over the long run. Furthermore, if TEP believes that "costs will escalate" and it will be "forced to invest in less productive and more expensive programs" then committing to a long term plan, eliminating Commission oversight and setting a performance incentive that is not based on performance is not in the best interest of ratepayers.

Q. Any other concern with capitalizing the DSMS costs?

A. Another consideration for RUCO is that the artificially reduced DSMS rate masks the true cost of EE.

Q. Which rate of return will TEP use in its performance incentive in the EERP?

A. TEP proposes to apply its Weighted Average Cost of Capital (WACC) and not the Fair Value Rate of Return (FVROR). Since the WACC is higher than the FVROR, applying the WACC instead of the FVROR further enriches the EERP's performance incentive. When adding an additional 200 basis points to the cost of equity using the WACC, TEP would receive a 8.67% return on its DSM/EE programs.

FVROR	5.68%
WACC	7.74%
EERP	8.67%

Q. Please discuss further why RUCO does not find value in paying carrying costs plus a premium for the benefit of a lower DSMS rate.

A. Mr. Jones's testimony compares the DSMS rate impact for the average residential ratepayer if costs are capitalized or expensed.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Current Method	$2.04	$2.69	$2.74	$0	$0	$0
EERP Method	$0.81	$1.45	$2.16	$1.99	$1.31	$0.64
Difference	($1.23)	($1.23)	($0.58)	**$1.99**	**$1.31**	**$0.64**

Under the EERP proposal, ratepayers pay an extra $16,978,900 for the "benefit" of paying $1.23 ***less*** in 2014 and 2015, $0.58 ***less*** in 2016, but paying $1.99 ***more*** in 2017, $1.31 ***more*** in 2018 and $0.64 ***more*** in 2019. Moreover, these costs, beginning in 2017, would be ***in addition to*** whatever EE program costs the Commission approves in those years.

Q. Is RUCO's sole objection about the rate of return plus premium incentive the fact that $16.9 million is added to the EE budget?

A. No. RUCO understands that the proposed $79.6 million is only for the actual program costs. The $16.9 million, which is in addition to the $79.6 million, is not of value to ratepayers. Finally, the rate of return would also be in addition to the $79.6 million that the Company is requesting.

Q. What if, hypothetically, a performance-based incentive came out to be the same amount as the rate of return plus premium incentive? Would this overcome RUCO's objection?

A. Not really. First, RUCO believes that an incentive should be based on performance and not on the amount spent. Second, RUCO suspects that the rate of return plus premium incentive is more generous than a performance incentive.[7]

EERP CONTAINS A PERFORMANCE INCENTIVE TH AT REWARDS SPENDING OVER PERFORMANCE

[7] RUCO does not have the details of an alternative incentive mechanism in order to compare the two models.

Q. TEP claims its EERP eliminates the Performance Incentive. Yet, RUCO contends that the Performance Incentive still exists but has taken a different form. Please explain the difference of opinion.

A. It is well established that applying a rate of return to EE program costs is a type of incentive. There are three (3) major types of incentive mechanisms:[8]

1. performance target incentives.
2. shared savings incentives.
3. rate of return adders.

As the American Council for an Energy-Efficiency Economy (ACEEE) states:

> "While program cost and lost margin recovery mechanisms serve to mitigate the utility disincentive to invest in energy efficiency due to a reduction in sales, they do not necessarily provide an incentive for such investment. Even with a decoupling mechanism in place, investor-owned utilities often still have an incentive to make supply side investments because of the beneficial effect on stock price...***Because performance incentives are relatively easier to enact than decoupling, they are widely used by states that have mechanisms in place beyond program cost recovery...Several common approaches include: Performance target incentives, shared savings incentives and <u>rate of return incentives</u>***." (Emphasis added) (See Attachment B or go to http://aceee.org/sector/state-policy/toolkit/utility-programs/performance-incentives)

[8] See "Aligning Utility Incentives with Investment in Energy Efficiency: "A Resource of the National Action Plan for Energy Efficiency.", p. ES-3 http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf

In a paper co-authored by Howard Geller of the Southwest Energy Efficiency Project (SWEEP), Mr. Geller identifies the various types of performance incentives:

> "Other states including Arizona, Connecticut, Massachusetts, Minnesota and Nevada have adopted performance incentives (also known as shareholder incentives) to reward utilities for implementing effective DSM programs and overcome their historical reluctance for doing so. ***Various approaches to performance incentives exist, including allowing utilities to earn a higher-than-normal rate of return*** on some or all DSM expenditures, allowing utilities to earn a bonus if they meet certain energy savings targets, or allowing utilities to keep a portion fo the net economic benefits resulting from their DSM programs." [9] (Emphasis added)

Q. What is the Performance Incentive – the entire rate of return plus the 200 basis point premium or solely the 200 basis points premium?

A. It could be argued that only the 200 basis points premium to the cost of equity is the performance incentive and that the rate of return covers the carrying costs necessary to compensate the utility for waiting four years for complete program cost recovery. However, RUCO finds that the entire rate of return plus the premium constitutes the performance incentive. RUCO comes to this conclusion because the entire rate applied to the DSM/EE programs is a bonus over and above the recovery of program costs and lost fixed costs needed to make the utility whole for its EE

[9] "Utah Energy Efficiency Strategy: Policy Options" http://www.swenergy.org/publications/documents/UT_Energy_Efficiency_Strategy.pdf)

programs. It is an even higher rate of return than the utility would have earned if it had placed new plant in service. And a performance incentive is intended, in part, to eliminate the financial disincentive to implement EE programs rather than to invest in new plant.

Q. Why should a utility even be given a performance incentive bonus? After all, in exchange for compliance with the EE Rules, the utility is made whole through recovery of program costs and is even afforded recovery of its lost fixed costs. In other words, what is the reason *the utility* supports a performance incentive?

A. In short, one purpose of a performance incentive is to eliminate the financial disincentive to choose energy efficiency over building new plant. Under traditional ratemaking principles, a utility earns a return (a profit) on capital invested in plant. Unless given an opportunity to earn a profit from its EE programs, there is an economic preference to invest in new plant rather than in EE programs because a utility is only made whole for its EE efforts but earns a return on capital investments.

Q. One purpose of a performance incentive is to eliminate the financial disincentive that favors adding plant over promoting energy efficiency. Isn't another equally – if not more important – objective of the performance incentive to incent superior performance in the

execution of cost efficient EE programs? In other words, what is the reason *<u>the ratepayer</u>* supports a performance incentive?

A. The ratepayer benefits when cost effective energy efficiency programs result in actual and sustained energy savings. When a utility selects EE programs that yield the greatest savings for the lowest cost, the ratepayers receive the maximum benefit. TEP's customers are captive – they have no choice but to receive service from TEP. A bonus structure that rewards the greatest results for the lowest costs is the best option for the ratepayer.

Q. Has the Commission expressed any guidance on how a performance incentive should be structured?

A. Yes. In the most recent APS rate case, the Commission ordered APS, Staff and stakeholders to develop a new performance incentive structure "*that optimizes the connection between energy efficiency, rates and utility business incentives that creates a clear connection between the level of performance incentive and achievement of cost-effective energy savings.*" (Decision. No. 73183)

Q. Does providing a rate of return plus premium as the incentive accomplish this purpose?

A. No. TEP's proposed rate of return plus premium incentive is tied to EE spending – not actual performance. There is no "clear connection between the level of performance incentive and achievement of cost-effective energy savings." TEP's proposed incentive is not in the ratepayers' interest because it: (1) incents the wrong behavior; (2) is not tied to cost effectiveness; (3) is not tied to results; and (4) rewards higher spending.

RUCO strongly believes that a performance incentive is appropriate when it is based on actual performance. This incents the utility to spend EE dollars on the most effective programs. TEP's proposal does not do this.

Under the EERP, TEP could fall short of meeting its energy efficiency objectives and still collect the full amount of the incentive. Alternatively, if TEP studiously selected the optimum programs and achieved greater EE savings, TEP would still receive the same incentive amount. Under TEP's proposal, there is no financial motivation to achieve excellence. There is also no financial incentive to meet the EE goal. As long as TEP selects programs, R&D projects and pilot programs that meet the criteria in the Plan of Administration, TEP receives the $16.9 million regardless of the amount of energy actually saved.

Under the terms of the EERP's Plan of Administration, the rate of return plus premium incentive will be added to the entire EE program costs. Some of the EE budget may be spent on programs that are unable to prove cost effectiveness, such as research and development and pilot programs. This is a further departure from a "clear connection between the level of performance incentive and achievement of cost-effective energy savings."

EERP's THREE YEAR TERM BINDS FUTURE COMMISSIONS

Q. Does RUCO have any concerns regarding the three year time period of the EERP?

A. Yes. RUCO has heard from the Commission on numerous occasions that it is opposed to long term commitments that set policy into the future and bind future Commissions. The EERP establishes a Plan of Administration and annual budgets for three (3) years. These elements of the EERP cement the EE policy of the Commission for TEP throughout that term. During the APS rate case hearing, on behalf of Chairman Pierce, CALJ Farmer stated:

> "One of the features of the proposed settlement agreement is that it allows the Commission to set public policy on DG and EE on an annual basis in the annual implementation plans. He says that he likes that flexibility ..." (APS Rate Case, Docket No. E-01345A-11-0224, Transcript Vol. II, p. 282)

Even if this particular Commission agrees that a multi-year plan is appropriate, in 2014, there will be a new Commission. Due to term limits, there will be at least one new Commissioner. That newly-constituted Commission will be bound by the EERP.

Q. What kind of changes could the Commission wish to make in the future?

A. While I can only speculate, it is reasonable to think that the Commission may wish to make – or, at a minimum, to have the option available to make – one or more of the following changes:

1. Change the level of EERP funding.
2. Change the inputs of the Societal Cost Test or switch to an entirely different test.
3. Require cost effectiveness at the measure level.
4. Require EE measures and programs to achieve a minimum cost effectiveness rating greater than 1.0.
5. Limit the amounts that may be spent on R&D programs.
6. Limit the amount that may be spent on pilot programs.

When DSM/EE Plans are approved on an annual basis, the Commission has the flexibility to make timely adjustments.

Q. But even if the Commission approved the 3-year EERP, doesn't it still retain the authority to open up the rate case and make a change?

A. Yes. It is possible but not simple. To go back and modify or terminate the EERP, the Commission would have to re-open the entire TEP rate case through a §40-252 procedure. Reopening the rate case, even for a specific, limited purpose, causes reactions on Wall Street and additional scrutiny from investment analysts. RUCO would argue that a §40-252 procedure brings greater regulatory uncertainty than having DSM/EE Plans approved on an annual basis.

There are further complications if the EERP is approved as part of a settlement agreement. First, altering the EERP would change a material provision of the agreement. Due process affords all parties to that agreement notice and an opportunity to be heard. Second, under standard settlement agreement terms, all parties who sign the agreement commit to support and defend all terms of the agreement. A settling party who, due to unforeseen circumstances at that time, may find the EERP ultimately to be adverse to its interests but would be bound by the terms of the agreement to continue to support a provision that it now sees as detrimental to its interests.

EERP ELIMINATES COMMISSION OVERSIGHT

Q. How does the EERP eliminate Commission oversight? After all, TEP states "the Commission and other interested parties *may review the costs* related to the EE investment with the annual DSM/EE

compliance filing and within the context of a rate case to determine prudency." (Jones Direct Testimony, p. 68)

A. The EERP takes control of the DSM/EE program out of the Commission's hands for the next three years. TEP states:

> "Rather than seeking Commission approval for annual stipends to support specific programs, we have proposed a three year pilot program that allows TEP to invest and recover the capital spent on cost effective energy efficiency measures..." (Bonavia Direct Testimony, p. 14)

Q. Who conducts the cost effectiveness test?

A. TEP

Q. Who selects the EE programs?

A. TEP.

Q. Will the Commission approve the measures and programs of the EERP?

A. No.

Q. What does "review of the costs" mean?

A. The Plan of Administration sets forth the inputs of the Societal Cost Test (SCT) and holds that as long as TEP applies these inputs and the programs or measure are cost effective, then "all costs will be fully recoverable" (Jones Direct Testimony, Exhibit CAJ-7, Plan of Administration, pp. 3-4) RUCO is doubtful that "review of costs" carries any meaningful authority.

EERP SEEKS APPROVAL OF A BUDGET WITHOUT PROVIDING PROGRAM SPECIFICS

Q. Could TEP spend the entire EERP budget on R&D or pilot programs that are not required to prove cost effectiveness?

A. While that is highly unlikely, the hypothetical proves a point. TEP has complete discretion to determine how to manage the overall EE budget. Under current practice, the Commission authorizes an itemized budget for individual programs and measures, for R&D and for any approved pilot programs.

The elimination of Commission oversight results in the possibility that EERP funds could be used in a manner consistent with the POA but contrary to the wishes of the Commission.

Q. Does RUCO have a concern with how "cost effectiveness" is defined?

A. Yes. The Plan of Administration states that "Any EE <u>*measure*</u> or <u>*program*</u> that passes the SCT as defined herein is determined to be cost-effective and all costs will be fully recoverable." While DSM measure is defined as a single practice, device or technology, a DSM program is "one or more DSM measures provided as part of a single offering to customers."[10]

Q. So what does that mean?

A. It means that cost effectiveness is effectively at the program level and not the measure level. This allows TEP to package or bundle measures that fall below 1.0 with measures that exceed 1.0 to come to a cumulative program cost effective score that is at least 1.0. The EERP allows for ratepayers to pay for less productive measures because they are bundled with some cost effective ones without Commission review and approval. And since the performance incentive is paid regardless of the level of energy savings, there is a heightened need for Commission approval of TEP's selected programs and measures.

Q. Does the EERP allow TEP to spend money on programs that are not cost effective?

A. Yes. Under the Plan of Administration, research and development and pilot programs are not required to demonstrate cost effectiveness. While the Commission has approved DSM funds for R&D and pilot programs in the past, because their cost effectiveness is difficult – if not impossible – to

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[10] RUCO does not have the expertise to determine whether the Societal Cost Test inputs in the POA are similar to or more lenient than the cost effectiveness test inputs used by Staff. RUCO does not opine whether the inputs for the Societal Cost Test, the identified Avoided Environmental Costs, or the Net Lifetime Energy Savings are properly defined.

prove, the Commission has provided heightened analysis and has generally been cautious with the ratepayers' money for these categories. Without Commission oversight, TEP has no external constraints when deciding how much money to spend for R&D and pilot programs.

Q. While we know that ratepayers will be $96.6 million over six years for three years of EE, do we know which programs and measures the utility will administer?

A. Not at this time. TEP Direct Testimony did not provide any information on which EE programs and measures, or R&D programs or pilot programs it will administer in 2013, 2014 and 2015. All we know is that the Plan of Administration gives the utility complete discretion as long as it applies the inputs and methodology found in Attachment A to the Plan of Administration.

Q. Does that conclude your testimony on TEP's proposed Energy Efficiency Resource Plan?

A. Yes it does

EXHIBIT
RUCO-9
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON

RATE DESIGN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2013

TABLE OF CONTENTS – RATE DESIGN

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EXECUTIVE SUMMARY

Based on RUCO's analysis of TEP's rate application the average residential customer will see their monthly bill increase from $85.17 to $89.85, a monthly increase of $4.68, or 5.5 percent.

RUCO's proposal is based on total revenue requirements of $883.3 million which includes a recommended revenue increase of $46.4 million.

RUCO is also recommending several changes to TEP's lifeline customers as proposed by the Company, however, is further proposing limiting any rate increase to the lifeline customer to the same percentage increase proposed for all other residential ratepayers.

INTRODUCTION

Q. Please state your name, position, employer and address.

A. My name is Robert B. Mease. I am Associate Chief of Accounting and Rates employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant and currently licensed in the state of West Virginia. My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding TEP's cost of service (CCOS) allocation and rate design and recommend appropriate changes.

Q. Mr. Mease, did you perform a detailed cost of service study?

A. No. While I did do a cursory review, I did not perform an indepth detailed study.

Q. Based on the review you did perform, did you see make any adjustments to the cost of service?

A. No. I did not make any adjustments.

RATE DESIGN OBJECTIVES

Q. Can you please explain the Company's objectives in this rate? application for simplification of the existing rate structure?

A. The Company's proposed rate design objectives are to consolidate, simplify, and modernize the existing rate structure.

...

Q. Why does TEP feel it necessary to consolidate and simplify the existing rate structure?

A. Currently the Company has over 50 retail service rates with multiple variations in many classes. Many of these rates provide little if any incremental benefits through the numerous options. The numerous options to customers add unnecessary confusion for many customers, and increase costs associated with necessary modifications to the billing system and require additional education of both internal personnel and customer base. By consolidating many of the existing rates TEP hopes to reduce the customer confusion and encourage customers to consider all options available to them.

TEP is proposing to eliminate "frozen" rates. The frozen rates do not accurately reflect the costs associated with the rate and the longer the increase is postponed the larger the impact on the customer when the rate is adjusted.

MARGIN ANALYSIS BY RATE CLASSIFICATION

Q. Can you please provide an analysis or breakdown of the margins for the various classes for TEP ratepayers?

A. Yes. Please see attached chart.

RATE CLASS	RUCO PROPOSED MARGIN	RUCO PROPOSED PPFAC	RUCO PROPOSED PPFAC	Percentage Margin
Residential Service	$ 262,215,394	$ 118,425,580	$380,640,974	44.36%
Residential Time Of Use	7,269,795	4,388,547	11,658,341	1.23%
Small General Service	133,185,475	62,017,156	195,202,631	22.53%
Small General Service Time of Use	7,679,515	4,109,473	11,788,988	1.30%
Irrigation & Water Pumping	4,217,005	3,248,547	7,465,552	0.71%
Large General Service	81,182,089	33,283,559	114,465,648	13.73%
Large General Service Time of Use	9,952,379	7,157,860	17,110,240	1.68%
Large Light & Pow er Service	18,722,540	10,401,627	29,124,167	3.17%
Large Light & Pow er Service Time of Use	22,234,423	16,041,270	38,275,693	3.76%
Mining Service	41,115,648	31,928,918	73,044,566	6.96%
Traffic Signals & Lighting Service	3,343,776	1,181,323	4,525,100	0.57%
	$ 591,118,038	$ 292,183,861	$883,301,900	100.00%

Q. Does RUCO propose any significant adjustments between the different classes of ratepayers?

A. No. RUCO believes that the current classification of ratepayers is sufficient and proposes no reclassifications

RESIDENTIAL RATES

Q. What has TEP proposed for an increase in the monthly charges for residential rate class R-01, which represents approximately 85 percent of the customer base and generates approximately 42 percent of the system margin?

A. The Company is proposing to increase residential customer charges from the current $7.00 per month to $12.00 per month for the standard residential customer and $15.00 for all residential TOU customers. This represents an increase of approximately 71 percent for non-TOU ratepayers and approximately 114 percent for TOU ratepayers.

Q. Why is TEP increasing the monthly fixed charges for the largest group of company and residential ratepayers?

A. As stated in Mr. Jones testimony, page 33, the proposed customer charge is still only 22 percent of the customer and demand charges identified in the CCOS for the residential customer and the charge is still well below the monthly customer charges that the Commission has previously approved for other electric customers.

Q. Does RUCO agree with this large increase in monthly charges for the residential ratepayer?

A. RUCO believes that the increase as proposed by the Company is excessive and provides a disincentive for the ratepayer to be energy efficient. With a higher monthly fixed charge the volumetric charges consequently are reduced. This in effect does not provide the customer with an incentive to be conservative.

Q. Has TEP proposed substantial changes in the monthly volumetric charges in the R-01 class of ratepayer?

A. Yes. Currently there are three tiers (0 – 500 kWh, 501 – 3,500 kWh and >3,500 kWh) for energy charges and the Company is proposing to eliminate the >3,500 kWh tier. The Company does not believe that the tier is necessary as this tier makes the rate overly complex and captures less than one percent of the overall usage of this class.

Q. Does RUCO agree with eliminating this tier for residential rate payers?

A. No. RUCO does not agree with eliminating this tier. Even though the Company indicates that this tier generates less than one percent of the usage in R-01 residential class, this explanation does not provide sufficient reasoning for elimination. By having the higher tier, the residential ratepayer would have the tendency to be more conservative in order to keep their monthly billing to a minimum.

Q. Has the Company identified those residential rates that they are proposing to eliminate and/or blend with other residential classes of rates?

A. Yes. The Company has identified twenty six residential rates, including lifeline rates, that they are proposing to eliminate and/or blend into existing rates.

...

Q. Does RUCO agree with the Company's proposal?

A. Yes. RUCO agrees with the elimination and blending of the rates identified by the Company. RUCO would expect to see a substantial reduction in administrative expenses as a result of this proposal.

Q. Can you please provide a summary of the Company's existing residential rates as well as the rates being proposed in this filing?

A. See chart below for TEP's R-01 residential classification of ratepayers which is approximately 85 percent of all TEP ratepayers.

RESIDENTIAL - R-01	PRESENT RATES	TEP PROPOSED	RUCO PROPOSED
Customer Charge - Single-Phase	$ 7.00	$ 12.00	$ 10.20
Summer			
1st 500 kWhs	$ 0.0469	$ 0.0617	$ 0.0496
Next 3,000 kWhs	$ 0.0690	$ 0.0837	$ 0.0703
3,501 kWhs and above	$ 0.0890	$ 0.0837	$ 0.0928
Winter			
1st 500 kWhs	$ 0.0473	$ 0.0467	$ 0.0477
Next 3,000 kWhs	$ 0.0673	$ 0.0687	$ 0.0731
3,501 kWhs and above	$ 0.0873	$ 0.0687	$ 0.0807
Purchased Power & Fuel			
Summer kWh	$ 0.0332	$ 0.0331	$ 0.0331
Winter kWh	$ 0.0257	$ 0.0307	$ 0.0307

LIFELINE RATES

Q. Can you please describe TEP's current concerns related to the existing lifeline ratepayers and rate structure?

A. The Company's low income rates are defined as lifeline rates. TEP indicates that the existing rate design is overly burdensome and unreasonable. TEP is concerned that other customers have to pay the subsidies created by the multiple rate options as well as the cost of administration. TEP believes that the complexities associated with the existing rates results in additional costs to serve lifeline customers, and the additional costs are being absorbed by the remaining ratepayers.

Q. What is the current rate structure for TEP's lifeline ratepayers?

A. The current tariff configuration and discount applications are overly complex and confusing. They contribute to the over 300 possible variations of residential rates that must be accommodated in the Company's billing system and tested any time a rate change occurs. Lifeline rates that were set as far back as Decision No. 56781 in 1990 have become confusing and are no longer cost justified. While multiple additional groups of customers and levels of discounts have been created since 1990, the lifeline rates have only been increased once in 20 years. Some rates have been frozen, so as to not impact a customer, even though they are no longer based on cost of service.

Additionally, the Company was required to allow these frozen rates to be portable, and eligible customers remain on 20 year old out-of-date rates. Allowing the rate to be mobile prevents these old obsolete rates from fading away, even through attrition.

The cumulative effect of past rate cases has created a situation where similar lifeline customer's are paying significantly different rates and the approximately 23,000 lifeline customers are being served on 20 different rates.[1]

Q. What is TEP proposing in this rate case related to lifeline ratepayers?

A. First, existing lifeline ratepayers on R-04, R-05 and R-08 will be moved to a new lifeline rate designed to offer a 25 percent discount on all volumetric charges and the existing R-06 ratepayers (approximately 70 percent of lifeline ratepayers) will receive a flat $10.00 per month discount. Second, lifeline ratepayers will no longer be exempt from PPFAC or DSMS charges. Third, TEP is proposing to eliminate the option to make a lifeline rate mobile. Fourth, lifeline ratepayers will be subject to annual requalification at the Company's request. Fifth, lifeline rates will be limited to ratepayers who qualify as below the 150 percent federally

[1] See Craig Jones testimony pages 69 to 71

defined poverty level. Lifeline ratepayers in the senior or medical category will receive the same discount as other lifeline ratepayers.[2]

Q. Does RUCO agree with the changes as proposed by TEP for lifeline rates?

A. Not entirely. RUCO agrees with TEP that lifeline rates can be consolidated into a more efficient rate structure. Consolidating rates for lifeline customers would not only create a less complex structure for the Company but would also be less confusing to the lifeline ratepayer. RUCO also agrees with the Company that annual requalification is necessary under certain circumstances and will prevent customers from taking advantage of reduced rates when not entitled to this benefit. RUCO agrees with the Company's proposal to eliminate the mobility option and that customers will qualify for the lifeline rate structure only if they are below the 150 percent federally defined poverty level. Finally, RUCO agrees that lifeline ratepayers should be subject to PPFAC or DSMS adjustments as other ratepayers.

Q. Does RUCO take exception to any of the changes the Company has proposed for lifeline ratepayers?

A. Yes. In reviewing the Company's proposed rate increases there are several cases where lifeline rate increases are in excess of 50 percent.

[2] See Craig Jones testimony page 71 and 72

RUCO believes that in these cases the increases the Company has proposed for lifeline rates are excessive. Any changes in rates for one class of customers should not exceed the percentage change for other residential ratepayers.

Q. Can you please provide a summary of the proposed rate increase to the different rate classes of lifeline ratepayers?

A. Yes. See the following chart.

		No. of Customers	Lifeline Proposed Inc. PPFAC	Discount Compared to Standard Rate	Calculated Discount	Percent Change to Annual Billing	Caculculated Current Rate	Limit to Lifeline Rate	Recalculated Increase Based on Limitation
Residential R-01									
Residential Lifeline	R-04-01	819	$ 795.87	$ 217.29	$ 177,961	24.8%	$ 637.72	6.00%	$ 675.98
Residential Lifeline	R-05-01	1,722	795.87	217.29	374,173	9.7%	725.50	6.00%	769.03
Residential Lifeline	R-08-01	1,046	795.85	217.29	227,285	39.7%	569.69	6.00%	603.87
Residential Lifeline	R-06-01	13,373	893.16	120.00	1,604,760	14.4%	780.73	6.00%	827.58
Residential TOU R-21F									
Residential Lifeline	R-04-21F	4	865.01	120.88	484	49.3%	579.38	6.00%	614.14
Residential Lifeline	R-05-21F	4	865.01	120.88	484	31.3%	658.80	6.00%	698.33
Residential Lifeline	R-08-21F	9	865.01	120.88	1,088	67.4%	516.73	6.00%	547.74
Residential Lifeline	R-06-21F	25	889.89	96.00	2,400	38.6%	642.06	6.00%	680.58
Residential TOU R-70F									
Residential Lifeline	R-04-70F	6	865.01	120.88	725	39.0%	622.31	6.00%	659.65
Residential Lifeline	R-05-70F	16	865.01	120.88	1,934	22.2%	707.86	6.00%	750.34
Residential Lifeline	R-08-70F	24	865.02	120.88	2,901	56.0%	554.50	6.00%	587.77
Residential Lifeline	R-06-70F	109	889.89	96.00	10,464	27.8%	696.31	6.00%	738.09
Residential TOU R-201AF									
Residential Lifeline	05-201AF	3	860.25	58.35	175	29.1%	666.34	6.00%	706.32
Residential Lifeline	08-201AF	12	860.25	58.35	700	63.6%	525.83	6.00%	557.37
Residential Lifeline	06-201AF	336	890.64	27.96	9,395	36.6%	652.01	6.00%	691.13
Residential TOU R-201BF									
Residential Lifeline	05-201BF	-	778.59	105.63	-	24.7%	624.37	6.00%	661.83
Residential Lifeline	06-201BF	12	778.22	96.00	1,152	30.8%	594.97	6.00%	630.67

This chart identifies the excessive increase in lifeline rates. As previously stated, RUCO proposes that the lifeline customer rate increases be limited to the rate increase being proposed for the residential ratepayer class taken as a whole.

Q. Does this conclude your testimony on rate design?

A. Yes.

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

RUCO PROPOSED RATE DESIGN - SUMMARY

LINE NO.	DESCRIPTION	(A) RUCO PROPOSED MARGIN	(B) RUCO PROPOSED PPFAC	(C) RUCO TOTAL REVENNUE REQUIREMENT	(D) PERCENTAGE PER MARGIN
1					
2	PER SCHEDULE H-1				
3					
4	Residential Service	$ 262,215,394	$ 118,425,580	$ 380,640,974	44.36%
5	Residential Time Of Use	7,269,795	4,388,547	11,658,341	1.23%
6	Small General Service	133,185,475	62,017,156	195,202,631	22.53%
7	Small General Service Time of Use	7,679,515	4,109,473	11,788,988	1.30%
8	Irrigation & Water Pumping	4,217,005	3,248,547	7,465,552	0.71%
9	Large General Service	81,182,089	33,283,559	114,465,648	13.73%
10	Large General Service Time of Use	9,952,379	7,157,860	17,110,240	1.68%
11	Large Light & Power Service	18,722,540	10,401,627	29,124,167	3.17%
12	Large Light & Power Service Time of Use	22,234,423	16,041,270	38,275,693	3.76%
13	Mining Service	41,115,648	31,928,918	73,044,566	6.96%
14	Traffic Signals & Lighting Service	3,343,776	1,181,323	4,525,100	0.57%
15					
16	TOTAL ADJUSTED REVENUES	$ 591,118,038	$ 292,183,861	$ 883,301,900	100.00%
17					
18		(A)	(B)	(C)	(D)
19			PERCENTAGE		
20		TOTAL	PER TOTAL	CUSTOMER	ADJUSTED
21		REVENUE	REVENUE	COUNT	SALES kWh
22					
23	Residential Service	$ 392,299,316	44.41%	367,409	3,829,031,022
24	Small General Service	214,457,172	24.28%	37,387	2,178,314,340
25	Large General Service	131,575,887	14.90%	622	1,261,678,481
26	Large Light & Power Service	140,444,426	15.90%	14	1,947,412,723
27	Lighting Service	4,525,100	0.51%	19,566	37,430,789
28					
29	TOTAL ADJUSTED REVENUES	$ 883,301,900	100.00%	424,998	9,253,867,355
30					
31		(A)	(B)	(C)	(D)
32				CUSTOMER	ADJUSTED
33	RESIDENTIAL SERVICE	MARGIN	PPFAC	COUNT	SALES kWh
34					
35	R-01 - NEW	$ 257,489,149	$ 113,726,221	347,779	3,559,030,499
36	R-201 AN - NEW	$ 7,298,198	$ 4,336,602	10,756	136,224,933
37	RESIDENTIAL TIME-OF-USE				
38	TOU R-80 NEW	$ 6,774,843	$ 4,021,763	8,075	118,997,877
39	TOU R-201 BN NEW	$ 528,959	$ 366,784	798	10,926,086
40	COMMUNITY SOLAR R-01	$ -	$ 362,757	-	3,851,627
41	LIFELINES DISCOUNT NON-TOU	$ (2,571,953)			
42	LIFELINES DISCOUNT TOU	$ (34,007)			
43					
44	RUCO RESIDENTIAL TOTAL PER BILL COUNT	$ 269,485,189	$ 122,814,127	367,409	3,829,031,022
45					
46	COMPANY RESIDENTIAL PROPOSED TOTALS	$ 300,799,863	$ 122,814,127	367,409	3,829,031,022
47					
48	DIFFERENCE				
49					
50					

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RUCO PROPOSED RATE DESIGN - SUMMARY CONT'D

	DESCRIPTION	(A) RUCO PROPOSED MARGIN	(B) RUCO PROPOSED PPFAC	(C) CUSTOMER COUNT	(D) ADJUSTED SALES kWh
51	"OTHER" SERVICE				
52					
53	SMALL GENERAL SERVICE				
54	SGS-10-NEW	$ 131,452,301	$ 60,116,429	35,639	1,888,524,435
55	GS-11 - NEW	3,348,854	1,861,843	339	58,614,700
56	PS-40 DISCOUNT	$ (1,615,680)			
57	C-10 OMMUNITY SOLAR		$ 38,884		
58	SGS-76N-NEW	$ 7,679,515	$ 4,109,473	924	123,590,518
59	PS-43 NEW	$ 2,581,353	$ 1,597,081	339	50,179,432
60	PS-31 NEW	1,635,652	1,651,466	146	57,405,255
61					
62	LARGE GENERAL SERVICE				
63	LGS 13 NEW	$ 81,049,538	$ 33,233,464	535	1,045,063,814
64	CONTRACT PSR	$ 132,551	$ 50,095		
65	LGS 85N NEW	$ 9,952,379	$ 7,157,860	87	216,614,667
66					
67	LARGE LIGHT & POWER SERVICE				
68	I-14	$ 18,722,540	$ 10,401,627	4	351,454,280
69	LLP 90N NEW	$ 21,406,201	$ 15,189,457	8	512,887,038
70	I90 CONTRACT	$ 828,222	$ 851,813		
71	MINING SERVICE	$ 41,115,648	$ 31,928,918	2	1,083,071,404
72					
73	TRAFFIC SIGNAL & LIGHTING SERVICE				
74	PS 41	$ 1,491,582	$ 938,547	1,251	29,734,586
75	LIGHTING	$ 1,852,194	$ 242,776	18,316	7,696,203
76					
77	RUCO "OTHER" TOTALS PER BILL COUNT	$ 321,632,849	$ 169,369,734	57,589	5,424,836,333
78					
79	COMPANY "OTHER" PROPOSED TOTALS	$ 371,708,356	$ 169,375,574	57,589	5,425,012,991
80	DIFFERENCE				
81					
82					
83	RUCO GRAND TOTALS PER BILL COUNT	$ 591,118,038	$ 292,183,861	424,998	9,253,867,355
84					
85	COMPANY GRAND TOTALS PER PROPOSED DESIGN	$ 672,508,219	$ 292,189,701	426,983	9,254,044,013
86					
87	DIFFERENCE				
88	Customer Count Difference Of 1,985 Is Based On TEP Reduced Proposed Rate Charge To $0.00 For Residential Service R-02;				
89	Therefore It Is Appropriate To Remove These Customers From Bill Determinents.				

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RUCO PROPOSED RATE DESIGN - SUMMARY CONT'D

LINE NO.	DESCRIPTION		(A)	(B)	(C)	(D)	(E)	(F)	(G)
			TEP TY ADJUSTED		TEP PROPOSED		RUCO PROPOSED		
1	**Residential Service**								
2	Total	$ 392,299,316	45%		44%		44%		
3	PPFAC							$ 122,814,127	
4	Fixed			12%		17%		$ 42,652,837	16%
5	Variable			88%		83%		226,832,352	84%
6	Margin	$ 269,485,189	46%	100%	45%	100%	46%	$ 269,485,189	100%
7									
8	**Small General Service**								
9	Total	$ 214,457,172	28%		27%		24%		
10	PPFAC							$ 69,375,177	
11	Fixed			3%		5%		$ 7,978,309	5%
12	Variable			97%		95%		137,103,686	95%
13	Margin	$ 145,081,995	31%	100%	28%	100%	25%	$ 145,081,995	100%
14									
15	**Large General Service**								
16	Total	$ 131,575,887	12%		14%		15%		
17	PPFAC							$ 40,441,419	
18	Fixed			4%		7%		$ 6,019,667	7%
19	Variable			96%		93%		85,114,801	93%
20	Margin	$ 91,134,468	12%	100%	14%	100%	15%	$ 91,134,468	100%
21									
22	**Large Light & Power Service**								
23	Total	$ 140,444,426	14%		15%		16%		
24	PPFAC							$ 58,371,815	
25	Fixed			0%		0%		$ 305,983	0%
26	Variable			100%		100%		81,766,627	100%
27	Margin	$ 82,072,610	11%	100%	13%	100%	14%	$ 82,072,610	100%
28									
29									
30	**Lighting Service**								
31	Total	$ 4,525,100	0%		1%		1%		
32	PPFAC							$ 1,181,323	
33	Fixed			55%		57%		$ 1,852,194	55%
34	Variable			45%		43%		1,491,582	45%
35	Margin	$ 3,343,776	1%	100%	1%	100%	1%	$ 3,343,776	100%
36	TOTAL REVENUES	$ 883,301,900	100%		100%		100%	$ 883,301,900	
37									
38	MARGIN REVENUES	$ 591,118,038	100%		100%		100%	$ 591,118,038	
39									
40									
41									
42									
43									
44									
45									
46									
47									

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1	**RESIDENTIAL- New**	**R-01 - NEW**						
2	Customer Charge - Single-Phase		4,169,631	-	4,169,631	$ 10.20	$ 42,527,897	
3	Customer Charge - Three-Phase		3,720	-	3,720	$ 15.30	$ 56,913	
4	Summer							$ 42,584,810
5	1st 500 kWhs		774,517,742	-	774,517,742	$ 0.049578	$ 38,398,719	
6	Next 3,000 kWhs		1,111,304,840	-	1,111,304,840	$ 0.070315	$ 78,141,400	
7	3,501 kWhs and above		25,660,435	-	25,660,435	$ 0.092754	$ 2,380,102	
8	Winter							
9	1st 500 kWhs		964,189,143	-	964,189,143	$ 0.047724	$ 46,015,085	
10	Next 3,000 kWhs		676,975,492	-	676,975,492	$ 0.073051	$ 49,453,932	
11	3,501 kWhs and above		6,382,846	-	6,382,846	$ 0.080701	$ 515,101	
12	Purchased Power & Fuel							$ 214,904,340
13	Summer kWh		1,911,483,017	-	1,911,483,017	$ 0.033075	$ 63,222,301	
14	Winter kWh		1,647,547,482	-	1,647,547,482	$ 0.030654	$ 50,503,921	
15								$ 113,726,221
16	TOTAL REVENUE - RESIDENTIAL- New							$ 371,215,371
17								
18	**RESIDENTIAL - Special Electric Service - New**	**R-201-AN-NEW**						
19	Customer Charge - Single Phase		129,075	-	129,075	$ 10.20	$ 1,316,497	$ 1,316,497
20	Summer							
21	1st 500 kWhs		27,210,039	-	27,210,039	$ 0.040712	$ 1,107,766	
22	Next 3,000 kWhs		38,863,107	-	38,863,107	$ 0.056256	$ 2,186,274	
23	3,501 kWhs and above		330,324	-	330,324	$ 0.058296	$ 19,256	
24	Winter							
25	1st 500 kWhs		36,548,595	-	36,548,595	$ 0.030809	$ 1,126,020	
26	Next 3,000 kWhs		33,098,403	-	33,098,403	$ 0.046353	$ 1,534,208	
27	3,501 kWhs and above		174,465	-	174,465	$ 0.046863	$ 8,176	
28	Purchased Power & Fuel							$ 5,981,701
29	Summer kWh		66,403,470	-	66,403,470	$ 0.03308	$ 2,196,295	
30	Winter kWh		69,821,463	-	69,821,463	$ 0.03065	$ 2,140,307	
31								$ 4,336,602
32	**TOTAL REVENUE - RESIDENTIAL Special Electric Service - New**							$ 11,634,800
33								
34	**RESIDENTIAL- Time-Of-Use - New**	**R-80 NEW**						
35	Customer Charge - Single Phase		96,901	-	96,901	$ 12.75	$ 1,235,414	$ 1,235,414
36	Summer On Peak kWh		38,269,931	-	38,269,931	$ 0.060494	$ 2,315,089	
37	Summer Off Peak kWh		26,030,842	-	26,030,842	$ 0.047248	$ 1,229,909	
38	Winter On Peak kWh		21,519,575	-	21,519,575	$ 0.036927	$ 794,652	
39	Winter Off Peak kWh		33,177,530	-	33,177,530	$ 0.036162	$ 1,199,779	
40	Purchased Power & Fuel							$ 5,539,429
41	Summer On Peak kWh		38,269,931	-	38,269,931	$ 0.038739	$ 1,482,539	
42	Summer Off Peak kWh		26,030,842	-	26,030,842	$ 0.030187	$ 785,797	
43	Winter On Peak kWh		21,519,575	-	21,519,575	$ 0.034305	$ 738,221	
44	Winter Off Peak kWh		33,177,530	-	33,177,530	$ 0.030599	$ 1,015,206	
45								$ 4,021,763
46	TOTAL REVENUE - RESIDENTIAL- Time-Of-Use							$ 10,796,605
47								
48								
49								
50								

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51	**RESIDENTIAL- Time-Of-Use Special Electric Service - New**	**TOU R-201-BN-NEW**						
52	Customer Charge - Single Phase		9,575	-	9,575	$ 12.75	$ 122,076	$ 122,076
53	Summer On Peak kWh		3,054,312	-	3,054,312	$ 0.043064	$ 131,532	
54	Summer Off Peak kWh		2,081,926	-	2,081,926	$ 0.042007	$ 87,455	
55	Winter On Peak kWh		2,280,693	-	2,280,693	$ 0.032865	$ 74,955	
56	Winter Off Peak kWh		3,509,155	-	3,509,155	$ 0.032185	$ 112,942	
57	Purchased Power & Fuel							$ 406,883
58	Summer On Peak kWh		3,054,312	-	3,054,312	$ 0.038739	$ 118,321	
59	Summer Off Peak kWh		2,081,926	-	2,081,926	$ 0.030187	$ 62,847	
60	Winter On Peak kWh		2,280,693	-	2,280,693	$ 0.034305	$ 78,238	
61	Winter Off Peak kWh		3,509,155	-	3,509,155	$ 0.030599	$ 107,377	
62								$ 366,784
63	TOTAL REVENUE - RESIDENTIAL- Time-Of-Use Special Electric Service							$ 895,743
64								
65	REVENUE - RESIDENTIAL- FIXED						$ 45,258,797	
66	REVENUE - RESIDENTIAL- VARIABLE						$ 226,832,352	
67	LIFELINE DISCOUNT Non-TOU						$ (2,571,953)	
68	LIFELINE DISCOUNT -TOU						$ (34,007)	
69	TOTAL REVENUE - RESIDENTIAL- MARGIN							$ 269,485,189
70	TOTAL REVENUE - RESIDENTIAL- PPFAC							$ 122,814,127
71	PPFAC DISCOUNT - Non-TOU							
72	PPFAC DISCOUNT -TOU							
73	**TOTAL RESIDENTIAL REVENUE**							$ 392,299,316
74								
75								
76	**Small General Service - New**	**SGS-10 NEW**						
77	Customer Charge - *Single-Phase*		215,020	-	215,020	$ 15.30	$ 3,289,625	
78	Customer Charge - Three-Phase		212,653	-	212,653	$ 20.40	$ 4,337,883	
79	Summer							$ 7,627,508
80	1st 500 kWhs		74,822,676	-	74,822,676	$ 0.058398	$ 4,369,500	
81	501 kWhs and above		844,467,249	-	844,467,249	$ 0.074777	$ 63,146,795	
82	Winter							
83	1st 500 kWhs		105,220,676	-	105,220,676	$ 0.043091	$ 4,534,020	
84	501 kWhs and above		864,013,835	-	864,013,835	$ 0.059929	$ 51,779,327	
85	Primary Metering Discount						$ (4,848)	$ 123,824,794
86	Purchased Power & Fuel							
87	Summer kWh		919,289,925	-	919,289,925	$ 0.033075	$ 30,405,514	
88	Winter kWh		969,234,510	-	969,234,510	$ 0.030654	$ 29,710,915	
89								$ 60,116,429
90	PS-40 Margin Discount							$ (1,615,680)
91	TOTAL REVENUE - Small General Service							$ 189,953,050
92								
93								
94								
95								
96								
97								
98								
99								
100								

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101	**Small General Service - Time-Of-Use - New**	**SGS-76N NEW**						
102	Customer Charge - Single Phase		11,088	-	11,088	$ 17.85	$ 197,910	$ 197,910
103	Summer On Peak kWh		29,840,723	-	29,840,723	$ 0.073017	$ 2,178,872	
104	Summer Off Peak kWh		28,458,762	-	28,458,762	$ 0.065363	$ 1,860,149	
105	Winter On Peak kWh		26,052,011	-	26,052,011	$ 0.057327	$ 1,493,472	
106	Winter Off Peak kWh		39,239,023	-	39,239,023	$ 0.049673	$ 1,949,112	
107	Purchased Power & Fuel							$ 7,481,605
108	Summer On Peak kWh		29,840,723	-	29,840,723	$ 0.038739	$ 1,156,000	
109	Summer Off Peak kWh		28,458,762	-	28,458,762	$ 0.030187	$ 859,085	
110	Winter On Peak kWh		26,052,011	-	26,052,011	$ 0.034305	$ 893,714	
111	Winter Off Peak kWh		39,239,023	-	39,239,023	$ 0.030599	$ 1,200,675	
112								$ 4,109,473
113	TOTAL REVENUE - Small General Service - Time-Of-Use							$ 11,788,988
114								
115	**Mobile Home Park Service - New**	**GS-11 NEW**						
116	Customer Charge - Single Phase		3,722	-	3,722	$ 15.30	$ 56,938	
117	Customer Charge - Three Phase		346	-	346	$ 20.40	$ 7,066	$ 64,003
118	Summer All kWh		26,876,589	-	26,876,589	$ 0.064445	$ 1,732,049	
119	Winter All kWh		31,738,111	-	31,738,111	$ 0.049137	$ 1,559,517	
120	Primary Metering Discount						$ (3,285)	
121	Transformer Owned Discount						$ (3,430)	
122	Purchased Power & Fuel							$ 3,284,851
123	Summer kWh		26,876,589	-	26,876,589	$ 0.033075	$ 888,943	
124	Winter kWh		31,738,111	-	31,738,111	$ 0.030654	$ 972,900	
125								$ 1,861,843
126	TOTAL REVENUE - Mobile Home Park Service							$ 5,210,697
127								
128	**Firm Service Municipal Water Pumping Service - New**	**PS-43 NEW**						
129	Customer Charge		4,063	-	4,063	$ 15.30	$ 62,160	$ 62,160
130	Summer Delivery kWh		24,321,024	-	24,321,024	$ 0.058092	$ 1,412,855	
131	Winter Delivery kWh		25,858,408	-	25,858,408	$ 0.042784	$ 1,106,337	
132	Purchased Power & Fuel						$ -	$ 2,519,192
133	Summer kWh		24,321,024	-	24,321,024	$ 0.033075	$ 804,418	
134	Winter kWh		25,858,408	-	25,858,408	$ 0.030654	$ 792,664	
135								$ 1,597,081
136	TOTAL REVENUE - Firm Service Municipal Water Pumping Service							$ 4,178,434
137								
138	**Interruptible Agricultural Pumping - New**	**PS-31 NEW**						
139	Customer Charge		1,747	-	1,747	$ 15.30	$ 26,728	$ 26,728
140	Summer All kWh		31,079,701	-	31,079,701	$ 0.035304	$ 1,097,235	
141	Winter All kWh		26,325,555	-	26,325,555	$ 0.019437	$ 511,689	
142	Purchased Power & Fuel							$ 1,608,925
143	Summer kWh		31,079,701	-	31,079,701	$ 0.029768	$ 925,181	
144	Winter kWh		26,325,555	-	26,325,555	$ 0.027589	$ 726,285	
145								$ 1,651,466
146	TOTAL REVENUE - Interruptible Agricultural Pumping							$ 3,287,118
147								
148								
149								
150								

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151	**Large General Service - New**	**LGS-13 NEW**						
152	Customer Charge		6,420	-	6,420	$ 764.96	$ 4,911,030	$ 4,911,030
153	All Demand kW		3,277,679	-	3,277,679	$ 21.00	$ 68,831,262	
154	Energy							
155	Summer kWh		494,868,791	-	494,868,791	$ 0.007219	$ 3,572,681	
156	Winter kWh		550,195,023	-	550,195,023	$ 0.006902	$ 3,797,508	
157	Primary Metering Discount						$ (35,628)	
158	Transformer Owned Discount						$ (27,317)	
159	Purchased Power & Fuel							$ 76,138,508
160	Summer kWh		494,868,791	-	494,868,791	$ 0.033075	$ 16,367,785	
161	Winter kWh		550,195,023	-	550,195,023	$ 0.030654	$ 16,865,678	
162								$ 33,233,464
163	TOTAL REVENUE - Large General Service							$ 114,283,001
164								
165	**Large General Service - Time-Of-Use - New**	**LGS-85N NEW**						
166	Customer Charge		1,044	-	1,044	$ 934.95	$ 976,086	$ 976,086
167	Demand							
168	Summer On-Peak kW		190,618	-	190,618	$ 20.00	$ 3,812,361	
169	Summer Off-peak kW		131,265	-	131,265			
170	Winter On-Peak kW		257,042	-	257,042	$ 18.00	$ 4,626,749	
171	Winter Off-peak kW		161,933	-	161,933			
172	Energy							
173	Summer On-peak kWh		48,988,303	(39,915)	48,948,388	$ 0.003576	$ 175,048	
174	Summer Off-peak kWh		49,196,404	(40,084)	49,156,320	$ 0.002940	$ 144,540	
175	Winter On-peak kWh		40,905,653	(33,329)	40,872,324	$ 0.002305	$ 94,196	
176	Winter Off-peak kWh		77,700,944	(63,309)	77,637,635	$ 0.001589	$ 123,398	
177	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weight			(176,637)				
178	Purchased Power & Fuel							$ 8,976,293
179	Summer On-peak kWh		48,988,303	(39,915)	48,948,388	$ 0.038739	$ 1,896,212	
180	Summer Off-peak kWh		49,196,404	(40,084)	49,156,320	$ 0.030187	$ 1,483,889	
181	Winter On-peak kWh		40,905,653	(33,329)	40,872,324	$ 0.034305	$ 1,402,111	
182	Winter Off-peak kWh		77,700,944	(63,309)	77,637,635	$ 0.030599	$ 2,375,649	
183	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weight			(176,637)				
184								$ 7,157,860
185	TOTAL REVENUE - Time-Of-Use Large General Service							$ 17,110,240
186								
187	**Large Light & Power**	**I-14**						
188	Customer Charge		48	-	48	$ 1,699.91	$ 81,596	$ 81,596
189	All Demand kW		775,035	-	775,035	$ 21.00	$ 16,275,730	
190	Energy							
191	Summer kWh		164,577,383	-	164,577,383	$ 0.007152	$ 1,177,116	
192	Winter kWh		186,876,897	-	186,876,897	$ 0.006358	$ 1,188,098	
193	Purchased Power & Fuel							$ 18,640,944
194	Summer kWh		164,577,383	-	164,577,383	$ 0.030795	$ 5,068,161	
195	Winter kWh		186,876,897	-	186,876,897	$ 0.028540	$ 5,333,467	
196								$ 10,401,627
197	TOTAL REVENUE - Large Light & Power							$ 29,124,167
198								
199								
200								

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Test Year Ended December 31, 2011

Schedule RBM-2
Pages 1 Thru 6

RUCO PROPOSED RATE DESIGN

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) TEP PROPOSED BILL DETERMINENTS	(C) RUCO ADJUSTMENTS	(D) RUCO PROP'D BILL DETERM'TS	(E) RUCO PROP'D RATES AND CHARGES	(F) RUCO PROPOSED REVENUE CALCULATION	(G) RUCO PROPOSED REVENUE BY CUST. CLASS
201	**Large Light & Power - Time-Of-Use - New**	I-90N NEW						
202	Customer Charge		96	-	96	$ 1,869.90	$ 179,510	$ 179,510
203	Demand							
204	Summer kW		389,779	-	389,779	$ 22.00	$ 8,575,130	
205	Winter kW		553,780	-	553,780	$ 19.00	$ 10,521,824	
206	Energy							
207	Summer On Peak kWh		110,511,318	(5)	110,511,314	$ 0.004848	$ 535,727	
208	Summer Off Peak kWh		122,033,912	(5)	122,033,907	$ 0.004053	$ 494,604	
209	Winter On Peak kWh		93,840,290	(4)	93,840,286	$ 0.004450	$ 417,623	
210	Winter Off Peak kWh		186,501,539	(8)	186,501,531	$ 0.003656	$ 681,784	
211	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weighted			(21)				
212	Purchased Power & Fuel							$ 21,226,691
213	Summer On Peak kWh		110,511,318	(5)	110,511,314	$ 0.034837	$ 3,849,883	
214	Summer Off Peak kWh		122,033,912	(5)	122,033,907	$ 0.027146	$ 3,312,732	
215	Winter On Peak kWh		93,840,290	(4)	93,840,286	$ 0.030849	$ 2,894,879	
216	Winter Off Peak kWh		186,501,539	(8)	186,501,531	$ 0.027517	$ 5,131,963	
217	Adjustment Reflects Difference Between TEP TY Ajusted & Proposed Bill Determinents. Commodity Count Is The Weighted			(21)				
218								$ 15,189,457
219	TOTAL REVENUE - Large Light & Power - Time-Of-Use - New							$ 36,595,658
220								
221	**Mining**							
222	Customer Charge		24	-	24	$ 1,869.90	$ 44,878	$ 44,878
223	Demand							
224	Summer On Peak kW		762,919	-	762,919	$ 22.00	$ 16,784,209	
225	Summer Off Peak kW							
226	Winter On Peak kW		1,043,162	-	1,043,162	$ 19.00	$ 19,820,073	
227	Winter Off Peak kW							
228	Energy							
229	Summer On Peak kWh		204,784,496	-	204,784,496	$ 0.004848	$ 992,736	
230	Summer Off Peak kWh		233,607,818	-	233,607,818	$ 0.004053	$ 946,813	
231	Winter On Peak kWh		214,192,112	-	214,192,112	$ 0.004450	$ 953,231	
232	Winter Off Peak kWh		430,486,978	-	430,486,978	$ 0.003656	$ 1,573,709	
233	Purchased Power & Fuel							$ 41,070,771
234	Summer On Peak kWh		204,784,496	-	204,784,496	$ 0.034837	$ 7,134,077	
235	Summer Off Peak kWh		233,607,818	-	233,607,818	$ 0.027146	$ 6,341,518	
236	Winter On Peak kWh		214,192,112	-	214,192,112	$ 0.030849	$ 6,607,612	
237	Winter Off Peak kWh		430,486,978	-	430,486,978	$ 0.027517	$ 11,845,710	
238								$ 31,928,918
239	TOTAL REVENUE - Mining							$ 73,044,566
240								
241	**Traffic Signal & Street Light Service**	PS-41						
242	Customer Charge		15,006	-	15,006			$ -
243	Summer All kWh		11,178,373	-	11,178,373	$ 0.060772	$ 679,328	
244	Winter All kWh		18,556,213	-	18,556,213	$ 0.043773	$ 812,254	
245	Purchased Power & Fuel							$ 1,491,582
246	Summer kWh		11,178,373	-	11,178,373	$ 0.033075	$ 369,725	
247	Winter kWh		18,556,213	-	18,556,213	$ 0.030654	$ 568,822	
248								$ 938,547
249	TOTAL REVENUE - Traffic Signal & Light Service							$ 2,430,129
250								

Tucson Electric Power Company
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RUCO PROPOSED RATE DESIGN

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) TEP PROPOSED BILL DETERMINENTS	(C) RUCO ADJUSTMENTS	(D) RUCO PROP'D BILL DETERM'TS	(E) RUCO PROP'D RATES AND CHARGES	(F) RUCO PROPOSED REVENUE CALCULATION	(G) RUCO PROPOSED REVENUE BY CUST. CLASS
251	**Lighting Service**							
252	55 Watt		1,428	-	1,428	$ 8.21	$ 11,726	
253	70 Watt		2,472	-	2,472	$ 8.21	$ 20,298	
254	100 Watt		121,283	-	121,283	$ 8.21	$ 995,871	
255	250 Watt		19,574	-	19,574	$ 12.32	$ 241,165	
256	400 Watt		3,904	-	3,904	$ 19.01	$ 74,198	
257	Underground		23,986	-	23,986	$ 15.57	$ 373,543	
258	Pole		47,144	-	47,144	$ 2.87	$ 135,394	
259								$ 1,852,194
260	Purchase Power & Fuel							
261	400 Watt							
262	Summer kWh		2,832,315	-	2,832,315	$ 0.03308	$ 93,679	
263	Winter kWh		4,863,888	-	4,863,888	$ 0.03065	$ 149,098	
264	TOTAL REVENUE - Lighting Service							$ 242,776
265								$ 2,094,971
266	TOTAL REVENUE - Community General Service Solar	GS-03-10					$ 38,884	
267								
268	REVENUE - OTHER- FIXED						$ 15,368,696	
269	REVENUE - OTHER- VARIABLE						$ 306,264,154	
270	REVENUE - OTHER - MARGIN							$ 321,632,849
271	REVENUE - OTHER - PPFAC							$ 169,369,734
272	**TOTAL OTHER REVENUE**							$ 491,002,584
273								
274	**TOTAL RESIDENTIAL REVENUE**							$ 392,299,316
275	Unreconciled Difference Between TEP TY Adjusted And TEP Proposed Bill Detreminents							$ 6,389
276	**TOTAL RUCO PROPOSED REVENUE**							$ 883,308,288
277								
278								
279								
280	TOTAL TEP PROPOSED REVENUE							$ 883,308,288
281								
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Schedule RBM-3
Page 1 of 1

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A) PRESENT RATES	(B) TEP PROPOSED	(C) RUCO PROPOSED
1	**RESIDENTIAL - R-01 - New**			
2	Customer Charge - Single-Phase	$ 7.00	$ 12.00	$ 10.20
3				
4	Summer			
5	1st 500 kWhs	$ 0.046925	$ 0.061700	$ 0.049578
6	Next 3,000 kWhs	$ 0.068960	$ 0.083700	$ 0.070315
7	3,501 kWhs and above	$ 0.088960	$ 0.083700	$ 0.092754
8	Winter			
9	1st 500 kWhs	$ 0.047309	$ 0.046700	$ 0.047724
10	Next 3,000 kWhs	$ 0.067309	$ 0.068700	$ 0.073051
11	3,501 kWhs and above	$ 0.087309	$ 0.068700	$ 0.080701
12	Purchased Power & Fuel			
13	Summer kWh	$ 0.033198	$ 0.033075	$ 0.033075
14	Winter kWh	$ 0.025698	$ 0.030654	$ 0.030654
15				
16				

LINE NO.	RESIDENTIAL BILL COMPARISONS	KWH USED	PRESENT MONTHLY COSTS	TEP PROPOSED MONTHLY COSTS	RUCO PROPOSED MONTHLY COSTS	RUCO PROPOSED MONTHLY INCREASE	RUCO PROPOSED MONTHLY INCREASE
20							
21	Total Monthly Electric Bills at Different Usage Levels (Includes PPFAC)						
22							
23	Residential Service - R-01 - Summer	250	$27.03	$35.69	$30.86	$3.83	14.18%
24	Present Summer Months - May - October (6 Months)	500	$47.06	$59.39	$51.53	$4.46	9.49%
25	Proposed Summer Months - May - September (6 Months)	1,000	$98.14	$117.78	$103.22	$5.08	5.18%
26		2,000	$200.30	$234.55	$206.61	$6.31	3.15%
27		3,500	$353.54	$409.71	$361.70	$8.16	2.31%
28		5,000	$536.77	$584.88	$550.44	$13.67	2.55%
29							
30	Residential Service - R-01 - Winter	250	$25.25	$31.34	$29.79	$4.54	17.99%
31	Present Winter Months - November - April (5 Months)	500	$43.50	$50.68	$49.39	$5.89	13.53%
32	Proposed Winter Months - October - April (7 Months)	1,000	$93.76	$101.56	$102.45	$8.69	9.27%
33		2,000	$159.36	$176.36	$181.08	$21.72	13.63%
34		3,500	$322.52	$348.74	$360.50	$37.98	11.78%
35		5,000	$492.04	$497.77	$527.54	$35.50	7.22%
36							
37	The Average Residential R-01 Customer's Summer Bill	1,053	$103.55	$123.96	$108.70	$5.15	4.97%
38	The Average Residential R-01 Customer's Winter Bill	657	$61.86	$67.49	$66.88	$5.03	8.12%
39							
40							
41							

EXHIBIT
RUCO-10
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 21, 2012

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EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's analysis of Tucson Electric Power Company's application for a permanent rate increase, filed with the Arizona Corporation Commission on July 2, 2012, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt a 10.00 percent cost of common equity. This 10.00 percent figure falls above the high side of the range of results obtained in RUCO's cost of equity analysis, and is 75 basis points lower than Tucson Electric Power Company's proposed 10.75 percent cost of common equity. The 10.00 percent figure takes into consideration the lower level of equity in RUCO's recommended capital structure as compared to RUCO's sample of electric companies that face similar risk.

Capital Structure – RUCO recommends that the Commission adopt Tucson Electric Power Company's actual end of test year capital structure comprised of 43.50 percent common equity, 55.97 percent long-term debt and 0.53 percent short-term debt.

Cost of Debt – RUCO recommends that the Commission adopt RUCO's recommended cost of long-term debt of 5.22 percent and cost of short-term debt of 1.42 percent which are Tucson Electric Power Company's actual end of test year costs of debt.

Original Cost Rate of Return – RUCO recommends that the Commission adopt a 7.28 percent weighted average cost of capital as the original cost rate of return for Tucson Electric Power Company. This 7.28 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 46 basis points lower than the 7.74 percent weighted average cost of capital being proposed by Tucson Electric Power Company.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 5.11 percent for Tucson Electric Power Company which is RUCO's 7.28 percent original cost rate of return minus RUCO's recommended inflation adjustment of 2.17 percent. The method used by RUCO to arrive at this 7.28 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in prior UNS Gas, Inc. and UNS Electric, Inc. rate case proceedings.

EXECUTIVE SUMMARY (Cont.)

RUCO disagrees with a number of inputs that Tucson Electric Power Company's cost of capital consultant used in both the discounted cash flow model and the capital asset pricing model which were used to develop Tucson Electric Power Company's proposed cost of common equity estimate of 10.75 percent. This includes forecasted yields on long-term U.S. Treasury instruments, and forecasted data on companies that make up the Standard & Poor's 500 stock index as opposed to the most recent actual yields and actual historic data.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to my direct testimony further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations based on my analysis of Tucson Electric Power Company's ("TEP" or the "Company") application for a permanent increase in rates ("Application").

Q. Is this your first case involving TEP?

A. No. I testified in TEP's prior rate case before the Commission.

Q. Briefly describe TEP.

A. TEP is based in Tucson, Arizona and is the second largest investor-owned electric utility in the state. The Company is a wholly owned subsidiary of UNS Energy Corporation ("UNS" or "Parent"), which is also based in Tucson. According to the most recent Value Line Investment Survey ("Value Line") report on the Company (Attachment D), TEP provides electricity to approximately 404,000 customers in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County in southern Arizona. TEP's customer base is comprised of 42.00 percent residential, 21.00 percent commercial, 34.00 percent industrial, and 3.00 percent other. TEP's generating sources include coal, 92.00 percent; and natural gas, 8.00 percent.

...

Q. Has TEP elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. TEP elected to perform a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to TEP's FVRB.

Q. Please explain your role in RUCO's analysis of TEP's Application.

A. I reviewed TEP's Application and performed a cost of capital analysis to determine both an original cost rate of return ("OCROR") and a fair value rate of return ("FVROR") on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended cost of common equity (TEP has no preferred stock) and my recommended costs of long-term and short-term debt. The recommendations contained in this testimony are based on information obtained from TEP's Application, responses to data requests, and from market-based research that I conducted during my analysis.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case and will present RUCO's OCROR and FVROR recommendations.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into six sections. First, the introduction I have just presented and second, a summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of return for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate within which the Company is operating. Fourth, I will discuss my recommended capital structure and my recommended cost of long-term debt. Fifth, I will discuss my recommended weighted average costs of capital for both my recommended OCROR and FVROR. In the sixth and final section of my testimony, I will comment on the Company's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am recommending that the Commission adopt a 10.00 percent cost of common equity. This 10.00 percent figure is 40 basis points higher than the range of results obtained in my cost of equity analysis, and is 75 basis points lower than TEP's proposed 10.75 percent cost of common equity.

Capital Structure – I am recommending that the Commission adopt TEP's actual end of test year capital structure comprised of 43.50 percent common equity, 55.97 percent long-term debt and 0.53 percent short-term debt.

Cost of Debt – I am recommending that the Commission adopt a cost of long-term debt of 5.22 percent and cost of short-term debt of 1.42 percent which are the Company's actual end of test year costs of debt.

Original Cost Rate of Return – I am recommending that the ACC adopt a 7.28 percent weighted average cost of capital as the original cost rate of return ("OCROR") for TEP. This 7.28 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 46 basis points lower than the 7.74 percent weighted average cost of capital being proposed by the Company.

<u>Fair Value Rate of Return</u> – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.11 percent which is my recommended 7.28 percent OCROR minus an inflation adjustment of 2.17 percent. The method I have used to arrive at this 5.11 percent figure is consistent with methods adopted by the Commission in prior rate case proceedings[1] and meets the fair value requirement of the Arizona Constitution.

Q Why do you believe that RUCO's recommended 7.28 percent OCROR and 5.11 percent FVROR are appropriate rates of return for TEP to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for TEP meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically

[1] UNS Electric, Inc., Decision No. 71914, dated September 30, 2010 and UNS Gas, Inc., Decision No. 71623, dated April 14, 2010

managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as TEP, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for TEP?

A. I am recommending a cost of equity of 10.00 percent (before any inflation adjustment used to arrive at a FVROR). My recommended 10.00 percent cost of equity figure falls just above the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.. The results of my DCF and CAPM analyses are summarized on page 3 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate the Company's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine the Company's cost of equity capital.

Q. In determining the rate of future dividend growth for the Company, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[2]

[2] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0. 60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[3] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[4] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

...

[3] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = <u>4.00%</u>

[4] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = <u>6.00%</u>

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

...

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[5] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - [(BV) \div (MP)]$

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

…

[5] Gordon, M.J., <u>The Cost of Capital to a Public Utility</u>, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[6], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill

[6] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group comprised of twenty publicly traded electric service providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of the Company?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although TEP's parent company is publicly-traded on the NYSE, TEP is not. Because of this situation, I used the aforementioned proxy that includes twenty electric utilities with similar risk characteristics as TEP in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the electric utilities included in your proxy for TEP?

A. Each of the thirteen electric utilities in my sample are tracked in the Value Line Investment Survey's ("Value Line") Electric Utility industry segment. Value Line follows electric utilities on a regional basis and issues quarterly updates on electric utilities located in the eastern, central and western portions of the U.S. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment A of my testimony contains Value Line's most recent evaluation on each of the companies that I included in the electric proxy group which I used for my cost of common equity analysis.

Q. Are these the same electric providers included in the proxy used by TEP's cost of equity witness?

A. Yes. These are the same electric providers used by Mr. John J. Reed, the Company's' cost of capital witness.

Q. Please explain your DCF growth rate calculations for the sample electric providers used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the electric companies included in my sample for an historical 5-year observation period from the beginning of 2007 to the end of 2011. Schedule WAR-5 also includes Value Line's projected 2012, 2013 and 2015-17 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the sample electric companies.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use American Elecric Power Company, Inc. (NYSE symbol AEP) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 10 through 13 of my testimony) to multiply AEP's earned return on common equity by its earnings retention ratio for each year in the 2007 to 2011 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AEP's average internal growth rate of 4.27 percent over the 2007 to 2011 time frame reflects an up and down pattern of growth that ranged from a high of 5.10 percent during 2007 and 2008 to a low of 3.12 percent during 2010. Value Line is predicting that growth will fall from 4.21 percent in 2011 to 3.87 percent in 2012 and continue to decline to 3.66 percent by the end of the 2015-17 time frame. After weighing Value Line's projections on earnings and dividend growth, I believe that a 3.80 percent rate of internal growth is within the realm of possibility for AEP (Schedule WAR-4, Page 1 of 2).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that the number of shares outstanding for AEP increased from 400.43 million to 483.42 million from 2007 to the end of the observation period in 2011. Value Line is predicting that this level will increase from 486.00 million in 2012 to 500.00 million by the end of 2017. Based on this data, I believe that a 0.70 percent growth in shares is not unreasonable for AEP (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for AEP is 3.92 percent (3.80 percent internal growth + 0.12 percent external growth – as calculated on Page 2 of Schedule WAR 4) and is shown on Page 1 of Schedule WAR-4.

Q. What is the average DCF dividend growth rate estimate for your sample utilities?

A. The average DCF dividend growth rate estimate for my sample is 5.47 percent as displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates on your sample companies compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my growth estimates with the five-year projections of analysts at both Value Line and Zacks Investment Research, Inc. ("Zacks") (Attachment B). My 5.47 percent estimate is 40 basis points lower than Zacks' average long-term EPS projection of 5.87 percent and is 24 basis points lower than Value Line's growth projection of 5.71 percent (which is an average of EPS, DPS and BVPS). My 5.47 percent estimate is 336 basis points higher than the 2.11 percent average of Value Line's historical growth results and 100 basis points higher than the 4.47 percent average of the growth data published by both Value Line and Zacks. My 5.47 percent growth estimate is 281 basis points higher than Value Line's 2.66 percent 5-year compound historical average of EPS, DPS and BVPS. On balance, I would say my 5.47 percent growth estimate, derived from Value Line data, is not out of line with the growth projections that are available to the investing public.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends of my sample companies for the next twelve-month period that appeared in Value Line's most recent Ratings and Reports quarterly updates on the electric utility industry. I then divided those figures by the eight-week average daily adjusted closing price per share of the appropriate utility's common stock. The eight-week observation period ran from October 9, 2012 to November 30, 2012, and the average dividend yield was 4.13 percent as exhibited on Schedule WAR-3.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric companies included in your sample?

A. As shown on Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.60 percent for the electric utilities included in my sample which is 547 basis points higher than the current 4.13 percent yield on a safer Baa/BBB-rated utility bond (Attachment C).

...

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[7], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[8] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification.

[7] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[8] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM is that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

where: k = the expected return of a given security,

r_f = risk-free rate of return,

$ß$ = beta coefficient, a statistical measurement of a security's systematic risk,

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

...

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments (Attachment C) will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[9] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my

[9] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yield on a 30-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated October 12, 2012 through November 30, 2012 (Attachment C). This resulted in a risk-free (r_f) rate of return of 2.86 percent.

Q. Why did you use the yield on a 30-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument more closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect. In prior rate cases I have relied on the yields of the 5-year Treasury instrument, however for the sake of argument in this case, I have used the higher yield of the longer term 30-

year Treasury bond. As I will discuss later in my testimony, the yields of long-term U.S. Treasury instruments are currently falling as a result of recent actions being undertaken by the U.S. Federal Reserve to stimulate the U.S. economy.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2011 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of long-term government bonds for the same eighty-four year period. The market risk premium (r_m - r_f) that results by using the geometric mean of these inputs is 4.10 percent (9.80% - 5.70% = 4.10%). The market risk premium that results by using the arithmetic mean calculation is 5.70 percent (11.80% - 6.10% = 5.70%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in my proxy were calculated by Value Line. The betas were published in the most recent Value Line quarterly updates on the electric utility industry that were available prior to the filing date of my testimony. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the electric companies included in my sample ranged from 0.65 to 0.95 with an average beta of 0.72.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.82 percent. My calculation using an arithmetic mean results in an average expected return of 6.98 percent. The results obtained from my CAPM analysis exceed the current 4.13 percent yield on a Baa/BBB-rated utility bond (Attachment C) by 169 to 285 basis points.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

...

METHOD	RESULTS
DCF	9.60%
CAPM	5.82% – 6.98%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 5.82 percent to 9.60 percent. My final recommended cost of common equity figure is 10.00 percent which is 40 basis points above the high end of the range of estimates shown above (Schedule WAR-1, Page 3) and 587 basis points higher than the current 4.13 percent yield on a safer Baa/BBB-rated utility bond. My higher 10.00 percent recommendation takes into account the lower level of equity in TEP's capital structure when compared to the level of equity in the average capital structures of the electric companies included in my proxy (a point that I will discuss later in my testimony).

As I will discuss in more detail in the next section of my testimony, my final estimate also takes into consideration current interest rates (as the cost of equity moves in the same direction as interest rates), the current state of the national economy – which could be sliding back into recession. My final estimate also takes into consideration the U.S. Federal Reserve's recent decisions not to raise interest rates at least through mid-2015.[10] I also took into consideration information on Arizona's economy and current

[10] U.S. Federal Reserve press release dated October 24, 2012: http://www.federalreserve.gov/newsevents/press/monetary/20121024a.htm

rate of unemployment in making my final cost of equity estimate. My final estimate also falls within the range of projected returns on book common equity that Value Line is projecting for the electric utility industry (Attachment A).

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 10.75 percent cost of equity capital proposed by the Company is 75 basis points higher than the 10.00 percent cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please describe your analysis of the current economic environment.

A. My analysis begins with a review of the economic events that have occurred between 1990 and the present in order to provide a background on how we got to where we are now. It also describes how the Board of Governors of the Federal Reserve System ("Federal Reserve" or "Fed") and its Federal Open Market Committee ("FOMC") used its interest rate-setting authority to stimulate the economy by cutting interest rates during recessionary periods and by raising interest rates to control inflation during times of robust economic growth. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve, then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

[11] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. **Did the Federal Reserve achieve its goals during this period?**

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000. Over the next ten years, the FOMC continued to stimulate the economy and keep inflation in check by raising and lowering the federal funds rate.

Q. How did the U.S. economy fare between 2001 and 2007?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Disappointing economic data releases, since the beginning of 2001, preceded the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon which are now regarded as a defining point during this economic slump. From January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times in order to stimulate growth. During this period, the federal funds rate fell from 6.50

percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent during a period in which the economic picture turned considerably brighter as both Inflation and unemployment fell, wages increased and the overall economy, despite continued problems in housing, grew briskly.[12]

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers, and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief. As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates. Once again, the Fed managed to engineer a soft landing.

[12] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

Q. What has been the state of the economy since 2007?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the beginning of what is now being referred to as the Great Recession; the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[13] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages, and securities linked to them, forced the Fed to inject $24 billion in funds (raised through its open market operations) into the credit markets.[14] By Friday, August 17, 2007, after a

[13] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[14] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [15] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point

[15] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[16] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has

[16] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

been described as the worst financial crisis since the 1930's[17]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008.

Q. Has the Fed taken any further action to stimulate the economy?

Yes. At the close of the FOMC's September 2011 meeting the Fed announced its decision to implement a plan that resembles a 1961 Federal Reserve program known as "Operation Twist".[18] Under this plan, the Fed would sell $400 billion in Treasury securities that mature within three years. The proceeds from these sales would then be reinvested into securities that mature in six to 30 years. This action would significantly alter the balance of the Fed's holdings toward long-term securities. In addition to selling off its shorter term Treasury holdings, the proceeds from the Fed's maturing mortgage-backed securities would be reinvested in other mortgage backed securities. Since 2010, the Fed had been reinvesting that money into Treasury bonds, shrinking its mortgage

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[17] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

[18] Hilsenrath, Jon and Luca Di Leo "Fed Launches New Stimulus" The Wall Street Journal, September 22, 2011

portfolio. The overall goal of the Fed's plan was to reduce long-term interest rates in the hope of boosting investment and spending and provide a shot in the arm to the beleaguered housing sector of the economy.

Q. Has there been any noticeable drop in long-term rates since the Fed announced its plan to purchase longer term Treasury instruments?

A. Yes. The yield on the 30-year Treasury bond has fallen from 2.88 percent to 2.82 percent since the latter part of November 2011 (Attachment C).

Q. What is the current rate of inflation in the U.S.?

A. As can be seen on Schedule WAR-8, the current rate of inflation, as measured by the consumer price index, is at 2.20 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[19]

Q. Has the Fed raised interest rates in anticipation of higher inflation?

A. No. The FOMC has not raised interest rates to date. The Fed's plan to buy $600 billion of U.S. government bonds over an eight month period, known as quantitative easing stage two or QE2,[20] was completed during

[19] http://www.bls.gov/news.release/cpi.nr0.htm

[20] Hilsenrath, Jon, "Fed Fires $600 Billion Stimulus Shot" The Wall Street Journal, November 4, 2010

the summer of 2011. The attempt to drive down long-term interest rates and encourage more borrowing and growth by increasing the money supply has yet to stimulate the economy and fears of a recession persist.

At its October 24, 2012 meeting, the FOMC announced that it will continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and continue, through the end of the year, its program to extend the average maturity of its holdings of Treasury securities. The FOMC also stated that it is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities. According to the FOMC, these actions, which together will increase the Committee's holdings of longer-term securities by about $85 billion each month through the end of the year, should put downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative. The FOMC further stated that it had decided to keep the target range for the federal funds rate at 0 to 0.25 percent. The FOMC currently anticipates that exceptionally low levels for the federal funds rate are likely to be warranted at least through mid-2015.

...

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected the yields on Treasury Instruments and benchmark interest rates?

A. As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year 2000 and U.S. Treasury instruments, are for the most part, still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has remained steady at 0.75 percent since November of 2011.

As of November 20, 2011, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have only increased 7 to 8 basis points from their November 2011 levels. Longer term yields including the 5-year, 10-year and 30-year have all fallen from levels that existed a year ago. The same is true for the 30-year Zero rate. The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[21], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates

[21] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

lengthen) presently exists. The 30-year Treasury yield, used in my CAPM analysis, has decreased 6 basis points from 2.88 percent, in November 2011, to 2.82 percent as of November 20, 2012.

Q. What are the current yields on utility bonds?

A. Referring again to Attachment C, as of November 20, 2012, 25/30-year A-rated utility bonds were yielding 3.78 percent (28 basis points lower than a year ago) and 25/30-year Baa/BBB-rated utility bonds were yielding 4.13 percent (down 61 basis points from a year earlier).

Q. What is the current outlook for the economy?

A. The current outlook on the economy includes fears that a slide into recession could occur if there is no resolution of the so called fiscal cliff situation (which involves the scheduled expiration of Bush Administration-era tax cuts and scheduled federal spending cuts) between the Executive Branch and Congress. Value line's analysts offered this perspective on the economy in the November 30, 2011 edition of Value Line's Selection and Opinion publication:

> "**We are starting to see Hurricane Sandy's impact on the final-quarter economy.** Of note, recent weeks have seen reports showing declines in retail spending, factory usage, and industrial production, with output in this last category estimated to have been reduced by nearly a percentage point by the storm. At the same time, jobless claims soared during the first part of November, due principally to disruptions from the hurricane."

Value Line's analysts went on to say:

"**Other disappointments could be on the way.** For example, reports for November may well show the storm's effect on payroll growth, the jobless rate, car sales, manufacturing, and non-manufacturing. We feel any step back will be brief — but still painful. Then, there is the fiscal cliff of mandated tax hikes and spending cuts that is set to kick in on January 2nd, unless Congress and the White House can author a deal. The fiscal cliff already is hurting business and consumer confidence and may, along with the toll from the hurricane, hold gross domestic product growth to less than 1.5% in the fast-ending quarter."

Value Line's analysts also stated:

"**Meanwhile, volatility is stepping up a notch on Wall Street,** which is understandable given the uncertain backdrop. Still, the fundamentals of a growing economy, low inflation, and a supportive Federal Reserve favor the bulls over the intermediate term. But first, investors may have to navigate through some choppy seas."

Q. How are electric utilities such as TEP faring in the current economic environment of low interest rates?

A. In the November 2, 2012 quarterly update (Attachment A) on the Electric Utility (West) Industry, Value Line analyst Paul E. Debbas, CFA had this to say:

"**The Effects of Interest Rates on Utilities**

Since 2008, interest rates have been low as a result of Federal Reserve policy. This has had various effects on utilities (and their stocks). Some of these effects are positive, some negative. The most noticeable effect on utilities is reflected in their stock prices. With interest rates on savings accounts, money market funds, and other income vehicles minuscule, many investors have chosen to turn to income stocks. Utilities are known for paying healthy dividends. Indeed, at 4.1%, this industry's average yield is well above the median yield of all dividend-paying equities under our coverage. Low interest rates also reduce utilities' borrowing costs—something that is important in such a capital-intensive sector. Interest savings from refinancing debt will eventually be passed on to customers once the utility receives a rate order. However, for debt held at the parent level or at a non-utility subsidiary, the company retains any interest reductions. Low interest rates also have some negative aspects for this industry. Allowed returns on equity have been trending down due to declining interest rates. Also, low interest rates

> increase a company's pension obligations because they are discounted at a lower rate. This can be reflected in higher pension expense. Finally, Hawaiian Electric Industries is unique in this group due to its ownership of American Savings Bank. Low interest rates are squeezing the interest-rate spreads for thrifts."

Also Included in Value Line's November 2, 2012 issue is its ranking of each state's regulatory climate, plus that of the District of Columbia and the Federal Energy Regulatory Commission ("FERC"). Value Line ranks states as above average, average and below average. Interestingly, Arizona was ranked as average along with Delaware, District of Columbia, Florida, Hawaii, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, South Dakota, Texas, Virginia, Washington, Wyoming.

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery.[22] During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures

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[22] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011.

occurring in Maricopa, Pinal and Pima Counties. As of this writing RealtyTrac is ranking Arizona as having the fifth highest foreclosure rate in the country. [23]

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on November 30, 2012, and displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics,[24] the seasonally adjusted unemployment rate for Arizona dropped two tenths of a percentage point from 8.2% in September 2012, to 8.1% in October 2012. At the time that this information was compiled, Arizona's rate of unemployment was higher than the U.S. unemployment rate of 7.9%.

More recent information on the national rate of unemployment, released by the U.S. Department of Labor on December 7, 2012, has pegged U.S. unemployment at 7.70 percent.

According to the November 30, 2012 Arizona Department of Administration's Office of Employment and Population Statistics report, the

[23] Associated Press: Arizona foreclosures keep on dropping," Arizona Capital Times, November 15, 2012.

[24] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/ .

October 2012 rates of unemployment for the counties that are served by TEP were as follows:

Selected County Unemployment Rates - October 2012

Cochise	7.8%
Pima	7.1%

Q. After weighing the economic information that you've just discussed, do you believe that the 10.00 percent cost of equity capital that you have estimated is reasonable for the Company?

A. I believe that my recommended 10.00 percent cost of equity capital, which is 587 basis points higher than the current 4.13 percent yield on a Baa/BBB-rated utility bond, will provide TEP with a reasonable rate of return on invested capital when data on interest rates (that are low by historical standards), the current state of the economy, current rates of unemployment (both nationally, in Arizona, and in the counties served by TEP), and the Fed's decision to keep interest rates at their current levels over the next three years are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of equity analysis, which is 40 basis points more than the high end of the range of results I obtained from both the DCF and CAPM models, has produced such a return.

CAPITAL STRUCTURE AND COST OF DEBT

Q. Please describe the Company-proposed capital structure.

A. The Company is proposing an adjusted end of test year capital structure comprised of 54.00 percent long-term debt and 46.00 percent common equity.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure containing 46.00 percent common equity is somewhat lower in equity than the capital structures of the electric companies in my sample, which had an average of 49.00 percent common equity, and would be perceived by investors as having somewhat lower risk overall. TEP's proposed 54.00 percent level of long-term debt is higher than the average of 50.90 percent in my sample and would be perceived as having a higher level of financial risk.

Q. What capital structure are you recommending for TEP?

A. I am recommending that the Commission Company's actual end of test year capital structure comprised of 43.50 percent common equity, 55.97 percent long-term debt and 0.53 percent short-term debt.

Q. Why are you recommending TEP's actual end of test year capital structure?

A. The actual end of test year capital structure is closer to the level of financing associated with RUCO's recommended level of utility plant in service which does not include all of the Company-proposed level of post-test year plant.

Q. Does your recommended cost of equity take into consideration the higher level of financial risk that TEP faces given the higher amount of debt in your recommended capital structure compared to the level in the capital structures of your sample electric companies?

A. Yes. My recommended 10.00 percent cost of common equity is 40 basis points higher than the 9.60 percent cost of equity derived from my sample of electric companies which, on average, had more balanced capital structures.

Q. Would you find a 10.00 percent cost of common equity to be appropriate if the Commission were to adopt the Company-proposed adjusted end of test year capital structure with a higher percentage of equity?

A. No. As discussed earlier in my direct testimony, my cost of capital analysis derived a cost of common equity of 9.60 percent from my sample of electric utilities, which had an average capital structure comprised of

46.00 percent common equity. This is the same percentage of common equity in the Company-proposed adjusted end of test year capital structure. If the Commission were to adopt TEP's proposed capital structure, the 9.60 percent cost of common equity derived from my sample should be the authorized cost of common equity.

Q. What cost of long-term debt are you recommending for TEP?

A. I am recommending that the Commission adopt TEP's actual end of test year cost of long-term debt of 5.22 percent and the Company's cost of short-term debt of 1.42 percent.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for TEP?

A. Based on my recommended capital structure, comprised of 43.50 percent common equity, 55.97 percent long-term debt and 0.53 percent short-term debt, I am recommending an original cost weighted average cost of capital of 7.28 percent (Schedule WAR-1, Page 1). This is the weighted average cost of my recommended cost of 10.00 percent common equity, my recommended cost of long-term debt of 5.22 percent and the my recommended cost of short-term debt of 1.42 percent.

Q. What fair value rate of return are you recommending for TEP?

A. I am recommending a FVROR of 5.11 percent (Schedule WAR-1, Page 1) which is 217 basis points lower than my OCROR of 7.28 percent. My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as TEP.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because TEP elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, TEP performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

Q. Does your recommended FVROR satisfy the requirements for determining a FVROR that resulted from the Commission's Chaparral City Water Company remand decision, which established the need to remove the inflation component from an OCROR?

A. Yes. On July 28, 2008, the Commission issued Decision No. 70441, in which stated the following:

> Our previous method was a shorthand method of ensuring that inflation would only influence one piece of the ratemaking formula - the rate of return. However, the Court of Appeals has made it clear that, under our constitution, the "inflation component" belongs in the FVRB. Accordingly, in order to avoid over-counting the effect of inflation, it is necessary for us to ensure that the rate of return does not also carry an inflation component. [Decision No. 70441, p. 33]

Q. How did you remove the inflation component from your OCROR?

A. I reduced my recommended costs of common equity and long-term debt by an inflation factor of 2.19 percent (Schedule WAR-1, Page 4). Because short-term debt is generally paid off in a year, I did not apply the inflation factor to my recommended cost of short-term debt. As a result of this decision, the effective difference between my OCROR and FVROR is 2.17 percent which produced my recommended FVROR of 5.11 percent. The method that I have used in this case produces a FVROR that is comparable to the FVROR calculated for UNS Electric, Inc. in a prior rate case proceeding. In that case the Commission adopted a method that reduced the OCROR by an inflation factor that was recommended by

RUCO.[25] The Commission had previously used the same method in a rate case proceeding for UNS Electric, Inc.'s sister utility, UNS Gas, Inc.

Q. How did you calculate your inflation factor of 2.18 percent?

A. By using the same RUCO methodology that produced an inflation factor similar to what the Commission relied on in the prior UNS Electric, Inc. case cited above. As can be seen on Page 4 of Schedule WAR-1, my recommended 2.18 percent inflation factor represents the difference between Treasury Inflation-Protected Securities ("TIPS") and comparable securities issued by the U.S. Treasury with similar liquidity and duration over a nine year period.

Q. How does your FVROR compare to the FVROR being recommended by TEP?

A. My recommended FVROR of 5.11 percent is 57 basis points lower than the 5.68 percent FVROR being proposed by TEP.

Q. What inflation factor does TEP propose?

A. TEP's cost of capital witness, Mr. Reed, is proposing an inflation adjustment of 1.56 percent, which is approximately a 50.00 percent

[25] Decision No. 71914, dated September 30, 2010

reduction to the 2.10 percent inflation factor that he calculated as requested by TEP.

COMMENTS ON THE COMPANY-PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed TEP's testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony prepared by Mr. John J. Reed.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 10.75 percent which is 75 basis points higher than my recommended 10.00 percent cost of equity.

Q. Have you studied the specific methods that Mr. Reed used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Mr. Reed use to arrive at his cost of common equity for TEP?

A. Mr. Reed used the constant growth DCF model similar to the one that I used and a multi-stage DCF. He also employed the CAPM and risk premium methods to estimate TEP's cost of common equity. I did not employ the risk premium methodology because this Commission has traditionally placed more weight on the results of the DCF and CAPM.

Q. Can you provide a comparison of the results derived from Mr. Reed's models and yours?

A. Yes. The following portion of my testimony will compare and contrast the results of our constant growth DCF and CAPM analyses.

DCF Comparison

Q. Please compare the results of Mr. Reed's DCF analyses and the results of your DCF analysis.

A. Mr. Reed presented the results of two DCF analyses that relied on the same of regulated electric utilities that I relied on. His constant growth DCF analysis produced estimates ranging from 9.66 percent to 12.06 percent. His multi-stage DCF analysis produced estimates ranging from 9.65 percent to 12.15 percent. My constant growth DCF analysis, which relied on the same sample of electric utilities included in Mr. Reed's sample, produced a final estimate of 9.60 percent.

Q. What was the difference between Mr. Reed's dividend yield results for electric utilities and your dividend yield results?

A. Mr. Reed's constant growth DCF analysis of regulated electric utilities produced an average dividend yield of 4.19 percent as opposed to my average dividend yield of 4.13 percent. I attribute the 6 basis point difference to slightly higher closing stock prices that I recorded during my more recent 8-week observation period since there is not that much difference in the average annualized dividends paid by our respective sample companies.

Q. Please compare your respective DCF growth estimates (g) for electric utilities.

A. Mr. Reed's constant growth DCF analysis produced an average growth estimate of 6.49 percent compared to my 5.47 percent estimate.

Q. Were there any differences in the way that you conducted your constant growth DCF analysis and the way that Mr. Reed conducted his?

A. Yes. Mr. Reed also relied on projections from First Call in addition to my reliance on Value Line and Zacks. The First Call growth projections of 6.88 percent were 141 basis points higher than my 5.47 percent average growth estimate. However, I will point out that Mr. Reed's DCF analysis was conducted prior to July of 2012 and analysts' growth estimates appear to have fallen since that time. Mr. Reed's 6.27 percent EPS growth estimate obtained from Zacks is 56 basis points higher than the more recent 5.75 percent that I obtained from Zacks.

CAPM Comparison

Q. Please compare the results of Mr. Reed's CAPM analysis and the results of your CAPM analysis.

A. Mr. Reed's CAPM analysis produced expected return estimates ranging from 10.33 percent to 10.85 percent for our sample of electric utilities. His estimates are 451 basis points to 503 basis points higher than my 5.82 percent CAPM estimate that uses a geometric mean and are 335 basis points to 387 basis points higher than my 6.98 percent CAPM estimate that uses an arithmetic mean. Mr. Reed's range of CAPM estimates exceeds the recent yield of 4.13 percent on a Baa/BBB-rated utility bond yield by 620 to 672 basis points.

Q. What are the main reasons for Mr. Reed's higher CAPM results?

A. There are two reasons. First, Mr. Reed's use of forecasted yields on the 30-year Treasury Bond which is used as a proxy for the risk free rate of return and second, the market risk premiums which utilized Mr. Reed's own method for calculating the return on the market as opposed to relying on the more established method of relying on historical market data published in Morningstar.

…

Q. Please describe the first difference in the way that you conducted your CAPM analysis and the way that Mr. Reed conducted his?

A. The first difference involves Mr. Reed's use of a then current 3.24 percent yield on a 30-year Treasury bond which has since fallen to 2.82 percent (Attachment C) and his reliance on higher forecasted estimates of the yield on the same 30-year Treasury instrument as opposed to the more recent 8-week average yields of the 30-year Treasury bond that I relied on for the risk-free rate of return.

Q. Do you believe that analyst's forecasted yields on U.S. Treasury instruments are appropriate?

A. No. I believe that the most current yield is the best indicator of future yields.

Q. What is the second difference between your respective CAPM analyses?

A. The second difference involves the market risk premium. Mr. Reed's market risk premiums were derived by subtracting Mr. Reed's aforementioned 30-year Treasury yields from a 12.97 percent estimated required market return on the S&P 500 obtained through a DCF model. His S&P 500 data consisted of forecasted dividend and growth estimates which produced higher market risk premiums ranging from 7.87 percent to 9.73 percent as opposed to my market risk premiums of 4.10 percent and

5.70 percent. Mr. Reed's higher market risk premiums are the result of his reliance on forecasted data as opposed to the Morningstar SBBI Yearbook actual historical data, which encompassed a much broader period of the U.S. economy between 1926 and 2011, that I relied on.

Q. Did Mr. Reed use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However, Mr. Reed's utility sample had an average Value Line beta of 0.731 as opposed to my average Value Line beta of 0.72 (which demonstrates that the Value Line betas for our sample companies are lower than what they were at the time that Mr. Reed prepared his testimony on TEP). Mr. Reed also relied on betas published by Bloomberg which averaged 0.729.

Q. What is the beta of UNS Energy Corporation, the parent of TEP?

A. UNS Energy Corporation has a Value Line beta of 0.70 which is lower than Mr. Reed's average Value Line utility sample betas of 0.731 and his Bloomberg average sample beta of 0.729. TEP's Parent's beta is also lower than my average Value Line beta of 0.72. This indicates that TEP's Parent is not as risky as the average of our respective sample electric utilities.

Q. How did Mr. Reed arrive at his final 10.75 percent cost of equity capital for TEP?

A. Mr. Reed's proposed cost of equity estimate of 10.75 percent was chosen by TEP based on the range of results obtained from his cost of capital analysis.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Reed or any other witness for TEP constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on TEP?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Chief of Accounting and Rates
Residential Utility Consumer Office
October 2011 – Present

Public Utilities Analyst V
Residential Utility Consumer Office
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona Public Service Company	E-01345A-08-0172	Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase
UNS Electric, Inc.	E-04204A-09-0206	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase
Bella Vista Water Company	W-02465A-09-0411 et al.	Rate Increase
Chaparral City Water Company	W-02113A-10-0309	Reorganization
Qwest Communications International	T-04190A-10-0194 et al.	Merger
CenturyLink, Inc.	T-04190A-10-0194 et al.	Merger
Southwest Gas Corporation	G-01551A-10-0458	Rate Increase
Arizona-American Water Company	W-01303A-10-0448	Rate Increase
Arizona-American Water Company	W-01303A-11-0101	Reorganization
Arizona-American Water Company	W-01303A-09-0343	Deconsolidation
Goodman Water Company	W-02500A-10-0382	Rate Increase
Arizona Water Company	W-01445A-10-0517	Rate Increase
Bermuda Water Company, Inc.	W-01812A-10-0521	Rate Increase
UNS Gas, Inc.	G-04204A-11-0158	Rate Increase
Arizona Public Service Company	E-01345A-11-0224	Rate Increase
Arizona Water Company	W-01445A-11-0310	Rate Increase
Pima Utility Company	W-02199A-11-0329 et al.	Rate Increase

ATTACHMENT A

All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

A court overturned a rule from the Environmental Protection Agency that was supposed to have taken effect in 2012. This doesn't mean that electric utilities are off the hook for environmental upgrades, however.

Regardless of any EPA rules, coal-fired generation has declined this year due to low gas prices.

Investors in dividend-paying stocks, such as utilities, are facing a tax increase next year, unless Congress acts.

Most equities in this Industry are expensively priced, compared to historical standards for utilities.

An Update On EPA Rules

In 2011, the U.S. Environmental Protection Agency issued a rule concerning cross-state air pollution. The new regulation was supposed to have taken effect in early 2012. The rule created much consternation from owners of coal-fired units due to the short time frame for compliance, and litigation ensued. The rule was put on hold by one court order, then struck down by another. This was welcome news for most electric utilities with coal-fired generation, some of which would have had to curtail the usage of coal-fired plants had this rule gone into effect as scheduled originally. EPA will have a chance to revise this rule.

However, utilities with coal-fired facilities are still facing stricter limits on mercury emissions, which will take effect in 2015. This will be costly for many companies, although some (such as FirstEnergy and *American Electric Power*) have found ways to lessen their expected expenditures. In fact, some utilities have closed or plan to close some coal-fired plants. The costs of compliance aren't the only reason for the closings. Low prices for wholesale power have made complying with the new rule uneconomical for some utilities.

A Shift From Coal To Gas

Electric utilities' plants are dispatched based on their variable production costs. Nuclear units are first in the merit order, usually followed by coal, then gas. However, with natural gas prices so low, some electric companies have shifted some of their production from coal to gas. According to the U.S. Energy Information Administration, in 2010 (the latest data available), coal was used to generate 45% of the nation's electricity, and natural gas' share was 24%. Based on information provided by various utilities, these figures will be quite different in 2012, although coal will still exceed gas.

This does not create a windfall for utilities. Most, if not all, of the lower fuel costs are passed on to customers. Even so, this is indirectly beneficial for utilities that are seeking base rate increases. It is easier for a utility to convince the regulators to raise its base electric rates if lower fuel costs will offset part of the rate hike.

The Dividend Tax Rate

In 2003, Congress (with the support of the Bush Administration) lowered the tax rate on dividend income to a maximum of 15%. The law was set to expire at the end of 2010, but was extended for two years. Unless Congress acts, the law will expire at the end of 2012, and dividend income will be taxed as ordinary income beginning in 2013. Many utilities, the Edison Electric Institute (a trade group for investor-owned electric utilities), and the American Gas Association are lobbying Congress to avoid this situation. Investors might well have to wait until after Election Day for this matter to be resolved.

Conclusion

With interest rates so low, electric utility stocks have gotten much attention from investors due to their high dividend yields. The average yield of equities in this industry is above 4%.

Electric utility issues usually trade at a below-market price-earnings ratio, unless earnings are depressed. (*ITC Holdings* is an exception.) However, several utilities are now trading at a price-earnings ratio that is above the market's. This is an indication of how expensively priced many of these equities have become. Another indication of their high valuation is the fact that many of them are trading within their 2015-2017 Target Price Range.

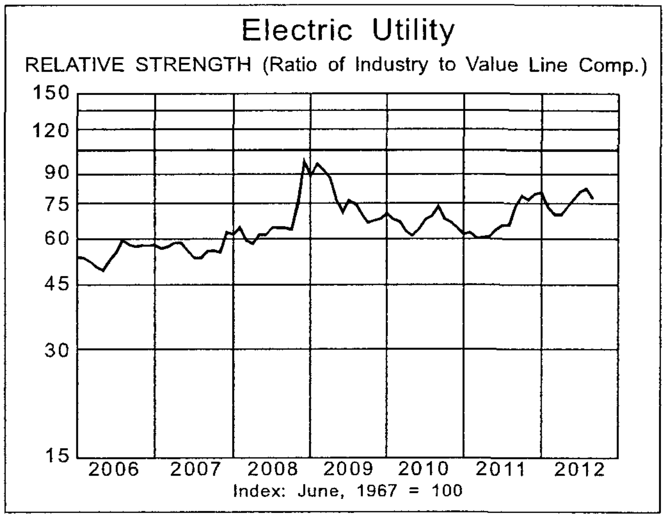
Paul E. Debbas, CFA

INDUSTRY TIMELINESS: 32 (of 98)

Composite Statistics: Electric Utility Industry

2008	2009	2010	2011	2012	2013		15-17
340.1	301.9	311.2	319.2	***290***	***305***	Revenues ($bill)	***350***
27.2	26.9	29.3	30.3	***27.0***	***29.0***	Net Profit ($bill)	***36.0***
33.3%	32.3%	34.1%	32.4%	***33.5%***	***34.0%***	Income Tax Rate	***34.0%***
7.8%	9.1%	8.8%	7.7%	***7.0%***	***7.0%***	AFUDC % to Net Profit	***6.0%***
53.4%	52.9%	52.6%	52.1%	***51.0%***	***51.0%***	Long-Term Debt Ratio	***50.5%***
45.6%	46.2%	46.6%	47.1%	***48.5%***	***48.5%***	Common Equity Ratio	***49.0%***
500.6	536.2	568.8	601.0	***570***	***595***	Total Capital ($bill)	***680***
538.2	580.6	625.2	688.9	***665***	***700***	Net Plant ($bill)	***800***
7.0%	6.5%	6.6%	6.5%	***6.0%***	***6.0%***	Return on Total Cap'l	***6.5%***
11.7%	10.7%	10.9%	10.5%	***9.5%***	***9.5%***	Return on Shr. Equity	***10.5%***
11.8%	10.8%	10.9%	10.6%	***9.5%***	***10.0%***	Return on Com Equity	***10.5%***
5.1%	4.3%	4.6%	4.1%	***3.5%***	***3.5%***	Retained to Com Eq	***4.0%***
57%	61%	59%	60%	***67%***	***64%***	All Div'ds to Net Prof	***61%***
15.0	12.5	12.8	13.8			Avg Ann'l P/E Ratio	***13.5***
.90	.83	.81	.87			Relative P/E Ratio	***.90***
6.0%	4.8%	4.6%	4.4%			Avg Ann'l Div'd Yield	***4.3%***

Bold figures are Value Line estimates



All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

We discuss regulatory climates for utilities and present the regulatory climate for almost every state, the District of Columbia, and the Federal Energy Regulatory Commission.

We discuss the effects of low interest rates on utilities. The effects aren't entirely positive.

In general, electric utility issues are expensively priced.

Ranking The Regulators

Occasionally, *The Value Line Investment Survey* publishes a list showing the regulatory climate in almost every state, the District of Columbia, and the Federal Energy Regulatory Commission (FERC). This is important because every electric utility will, at some point, have a regulatory proceeding before the state commission. This is true even in states that have deregulated the power-generation function, because the transmission and distribution functions remain regulated. For each electric utility under our coverage, we show the state's regulatory climate.

Electric utilities have been filing general rate cases more frequently in recent years, so investors ought to take note of the regulatory climate in the state or states in which the company operates. The increased regulatory activity is typically prompted by major capital projects that need to be placed in the rate base; rising operating and maintenance expenses; or a utility's ongoing inability to earn its allowed return on equity.

Strictly speaking, the regulatory climates are not rankings of the state regulatory commissions. To be sure, the regulatory commission plays the biggest role, in our evaluation, but a state's ranking is also influenced by the executive, legislative, and judicial branches of the state government.

Seven states are not included in the list below, either because investor-owned electric companies have little presence there or because we do not cover any companies that have significant operations there. These states are Alaska, Maine, Nebraska, Rhode Island, Tennessee, Utah, and Vermont.

- *Above Average:* Alabama, California, Colorado, Georgia, Idaho, Indiana, Massachusetts, Ohio, South Carolina, Wisconsin, FERC.
- *Average:* Arizona, Delaware, District of Columbia, Florida, Hawaii, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, South Dakota, Texas, Virginia, Washington, Wyoming.
- *Below Average:* Arkansas, Connecticut, Illinois, Maryland, New York, Oregon, West Virginia.

Since the last time we ran this table, we have raised Georgia's regulatory climate from Average to Above Average and lowered South Dakota's regulatory climate from Above Average to Average. Regulation in Georgia has been reasonable for Georgia Power (a subsidiary of Southern Company), and regulatory law in the state is allowing the utility to recover construction work in progress for the nuclear units that are being built. On the other hand, we could not justify keeping South Dakota at Above Average, given the poor returns and regulatory struggles that *Xcel Energy* is having there.

INDUSTRY TIMELINESS: 39 (of 98)

The Effects Of Interest Rates On Utilities

Since 2008, interest rates have been low as a result of Federal Reserve policy. This has had various effects on utilities (and their stocks). Some of these effects are positive, some negative.

The most noticeable effect on utilities is reflected in their stock prices. With interest rates on savings accounts, money market funds, and other income vehicles minuscule, many investors have chosen to turn to income stocks. Utilities are known for paying healthy dividends. Indeed, at 4.1%, this industry's average yield is well above the median yield of all dividend-paying equities under our coverage. Low interest rates also reduce utilities' borrowing costs—something that is important in such a capital-intensive sector. Interest savings from refinancing debt will eventually be passed on to customers once the utility receives a rate order. However, for debt held at the parent level or at a nonutility subsidiary, the company retains any interest reductions.

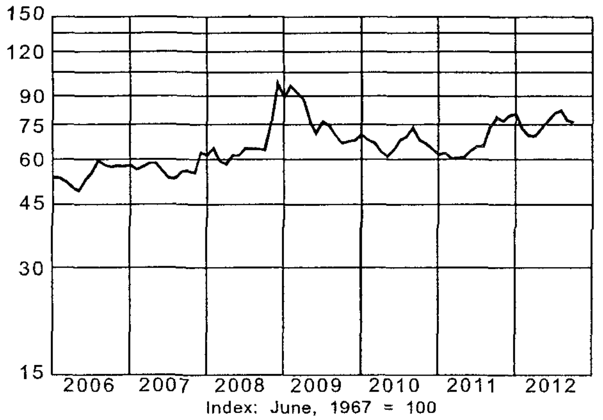
Low interest rates also have some negative aspects for this industry. Allowed returns on equity have been trending down due to declining interest rates. Also, low interest rates increase a company's pension obligations because they are discounted at a lower rate. This can be reflected in higher pension expense. Finally, *Hawaiian Electric Industries* is unique in this group due to its ownership of American Savings Bank. Low interest rates are squeezing the interest-rate spreads for thrifts.

Conclusion

The prices of many electric utility issues have risen to atypically high valuations. Several utility stocks are trading at a premium to the market price-earnings ratio, The vast majority have share prices that are within their 2015-2017 Target Price Ranges. Thus, it has become hard to find attractive electric utility selections. In particular, we would avoid the shares of *PG&E* and *Edison International.*

Paul E. Debbas, CFA

Electric Utility
RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

All of the major electric utilities located in the eastern region of the United States are reviewed in this Issue; central electrics, in Issue 5; and the remaining utilities, in Issue 11.

We discuss the effects of Hurricane Sandy on electric utilities.

Two utilities are building nuclear plants, and some other companies are expanding their nuclear capacity through uprate programs.

Electric utility stocks, as a group, haven't moved much in 2012, but many issues still have high valuations.

Hurricane Sandy

Hurricane Sandy hit the Northeast in late October—coincidentally, on the same date on which the region experienced a freak snowstorm a year earlier. More than eight million customers lost power, some for about two weeks. New Jersey and New York were hit the hardest, but the surrounding states were affected, too. *Consolidated Edison* estimates that its two utilities incurred costs of $425 million-$550 million. *FirstEnergy* is still tallying the costs, but estimates that they will amount to more than $500 million. *Exelon* estimated that the operating and maintenance costs due to the storm, which affected its utilities in Pennsylvania and Maryland, are $100 million. Public Service Electric and Gas (a subsidiary of *Public Service Enterprise Group*) is still assessing the restoration costs of the worst storm in the utility's history. Some of these expenses will be reflected in companies' bottom lines in the fourth quarter; others will be deferred, for future recovery from customers. Although some companies (such as *Dominion Resources*) typically exclude costs caused by severe weather from their definition of "operating" earnings, we *include* them in our presentation.

In the autumn of 2011, Connecticut Light & Power (a subsidiary of *Northeast Utilities*) received a lot of criticism from customers and state politicians because its outage lasted longer than those of other electric utilities in the region. The company wound up writing off part of the costs it incurred as a result of the aforementioned snowstorm. This illustrates a risk that utilities can face following a major weather disturbance. At least this utility's performance in response to Hurricane Sandy was much better.

Nuclear Construction

According to the conventional wisdom of the early 1990s, no electric utility in the United States was ever going to build another nuclear plant. Following the accident at Unit 2 of the Three Mile Island station in 1979, the next decade saw huge cost overruns in construction. Several mothballed or canceled plants led to regulatory disallowances and write-offs for utilities. This made the prospect of new nuclear construction unappealing.

In 2005, a federal law was passed to facilitate the construction of nuclear units. This involves an approval process by the Nuclear Regulatory Commission, based on a choice of specified designs, before construction begins. This was meant to avoid the changing regulations that caused construction costs to soar in the 1980s.

With construction of coal-fired plants increasingly unpopular due to environmental and political concerns, several utilities have considered building nuclear plants. Two have actually begun construction: Georgia Power (a subsidiary of *Southern Company*) and South Carolina Electric & Gas (a subsidiary of *SCANA*). Each company is building two units that are scheduled for completion in the second half of this decade. So far, each project has had some cost overruns, but these haven't been drastic.

INDUSTRY TIMELINESS: 36 (of 98)

What does it take for a utility to build nuclear units, besides lots of money? The company must have an adequate site. Georgia Power and SCE&G are building their units at the sites of existing nuclear facilities. The utility also needs a regulatory mechanism that allows it to recover construction work in progress in customers' rates. This lessens the financial strain on the company and allows it to avoid the rate shock that would occur if tariffs were raised sharply upon completion of the plants.

Some companies are adding nuclear capacity without building plants. Instead, they are expanding capacity of existing units by upgrading equipment. This is known as a nuclear "uprate." Florida Power & Light, (a subsidiary of *NextEra Energy*) is adding 526 megawatts of capacity at a cost of $2.95 billion-$3.15 billion. By the end of 2012, *Exelon* will have added 250 mw at some of its nuclear units (all of which are nonregulated) at a cost of nearly $1.2 billion. Low prices for wholesale power have induced the company to postpone uprates on two plants. Xcel Energy also plans to uprate one of its nuclear stations by 71 mw (pending NRC approval), but is deciding whether to expand the other one.

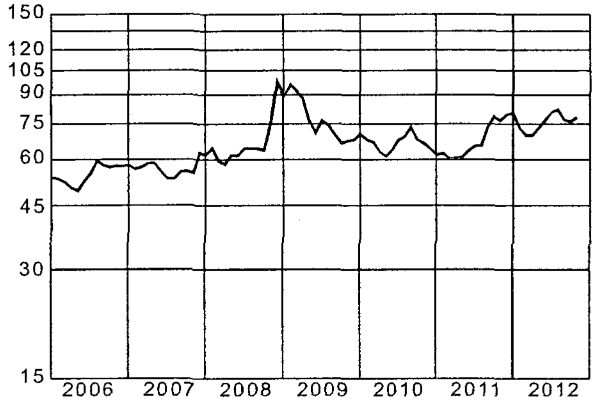
Conclusion

Following a pullback after Election Day, the Value Line Utility Average is down about 4% in 2012, falling far short of the broader market averages. We believe this is due to reversion to the mean; in 2011, utility issues were the outperformers. There has been a disparity in the performance of utility issues this year, with Sempra Energy stock having risen 20%, and *Exelon* shares having fallen more than 30%. Despite the relative underperformance, most stocks in this industry are still priced expensively. The majority of equities in the Electric Utility Industry are trading within their 3- to 5-year Target Price Ranges. Historically, this has been an indication that the group, as a whole, is overvalued.

Paul E. Debbas, CFA

Electric Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE	43.43	P/E RATIO	13.8 (Trailing: 14.1 / Median: 13.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	4.5%	VALUE LINE

TIMELINESS 3 Lowered 5/4/12

SAFETY 3 Lowered 10/4/02

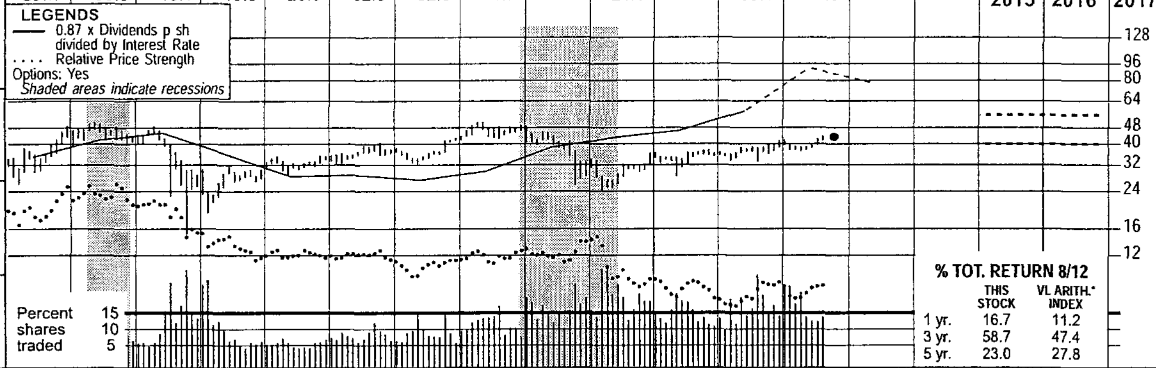
TECHNICAL 3 Lowered 9/14/12

BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	51.2	48.8	31.5	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	44.0
Low:	39.3	15.1	19.0	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0

Target Price Range

2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	10%
Low	40	(-10%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	339	323	312
to Sell	208	279	254
Hld's(000)	299983	298208	270699

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.7	11.2
3 yr.	58.7	47.4
5 yr.	23.0	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.07	32.43	33.08	35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	*30.65*	*32.30*	Revenues per sh	*36.50*
6.31	6.47	6.03	6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	*6.90*	*7.10*	"Cash Flow" per sh	*8.25*
3.14	3.28	2.81	2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	*3.10*	*3.10*	Earnings per sh A	*3.50*
2.40	2.40	2.40	2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	*1.90*	*1.96*	Div'd Decl'd per sh B ■	*2.15*
3.07	4.00	4.13	4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	*6.80*	*7.75*	Cap'l Spending per sh	*7.50*
24.15	24.62	25.24	25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	*31.60*	*32.80*	Book Value per sh C	*36.75*
188.24	189.99	191.82	194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	*486.00*	*489.00*	Common Shs Outst'g D	*500.00*
13.2	13.4	17.0	14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.83	.77	.88	.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	*Value Line*		Relative P/E Ratio	*.90*
5.8%	5.5%	5.0%	6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/12

Total Debt $18510 mill. Due in 5 Yrs $6372 mill.
LT Debt $15319 mill. LT Interest $844 mill.
Incl. $2389 mill. securitized bonds.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $316 mill.

Pension Assets-12/11 $4.30 bill. **Oblig.** $4.99 bill.

Pfd Stock None

Common Stock 484,902,556 shs.
as of 7/26/12

MARKET CAP: $21 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
14555	14545	14057	12111	12622	13380	14440	13489	14427	15116	*14900*	*15800*	Revenues ($mill)	*18200*
976.0	984.0	1038.0	1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	*1490*	*1500*	Net Profit ($mill)	*1725*
25.2%	38.8%	33.1%	29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	3.8%	3.6%	5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	*12.0%*	*12.0%*	AFUDC % to Net Profit	*12.0%*
56.0%	60.6%	56.2%	54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	*50.5%*	*50.0%*	Long-Term Debt Ratio	*49.0%*
43.1%	38.7%	43.1%	44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	*49.5%*	*50.0%*	Common Equity Ratio	*51.0%*
16393	20333	19584	20222	21902	24342	26290	28958	29184	29747	*30950*	*32125*	Total Capital ($mill)	*35900*
21684	22029	22801	24284	26781	29870	32987	34344	35674	36971	*38425*	*40250*	Net Plant ($mill)	*45100*
7.5%	6.6%	7.0%	6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
13.5%	12.3%	12.1%	11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
13.7%	12.4%	12.2%	11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	*10.0%*	*9.5%*	Return on Com Equity E	*9.5%*
2.4%	4.5%	5.7%	5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
82%	64%	54%	54%	53%	55%	55%	56%	66%	60%	*62%*	*64%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.4	+4.5	+1.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.83	4.95	4.95
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	265	257	286

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-10.5%	-2.0%	*3.5%*
"Cash Flow"	--	1.0%	*4.0%*
Earnings	2.0%	1.5%	*3.0%*
Dividends	-3.0%	4.0%	*3.5%*
Book Value	1.0%	5.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3458	3202	3547	3282	13489
2010	3569	3360	4064	3434	14427
2011	3730	3609	4333	3444	15116
2012	3625	3551	*4300*	*3424*	*14900*
2013	*3850*	*3750*	*4450*	*3750*	*15800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.89	.68	.93	.49	2.97
2010	.72	.35	1.16	.37	2.60
2011	.83	.73	1.17	.41	3.13
2012	.80	.75	*1.10*	*.45*	*3.10*
2013	*.85*	*.75*	*1.05*	*.45*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.41	.41	.41	.41	1.64
2009	.41	.41	.41	.41	1.64
2010	.41	.42	.42	.46	1.71
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47		

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.3 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 37%; commercial, 23%; industrial, 21%; wholesale, 16%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 35% of revenues. '11 reported depr. rates: 1.3%-9.3%. Has 18,700 employees. Chairman: Michael G. Morris. President & CEO: Nicholas K. Akins. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power will be making a transition to competitive markets in Ohio in the next few years. The Public Utilities Commission of Ohio (PUCO) issued a new plan in the third quarter. The PUCO overturned the previous transition plan earlier this year after some customers complained about much higher bills. AEP's base generation rates will be *frozen* (but there will be a fuel adjustment clause), and the utility will be able to collect a nonbypassable retail stability rider and a capacity charge to help compensate for the effects of customer switching to other suppliers. AEP will make another filing to separate its generating units in Ohio into a nonutility affiliate, except for two units that will be transferred to two regulated companies. Management was disappointed with certain aspects of the transition plan that the PUCO ordered, and has asked the regulators for a rehearing. Because the new plan will make it easier for other providers to compete in AEP's service territory, we have lowered our 2013 earnings estimate by $0.15 a share, to $3.10, which would be flat with our estimated 2012 tally.

Two rate cases are pending. Indiana Michigan Power filed for a $146.3 million rate hike in Indiana, based on an 11.15% return on equity. The commission's staff is recommending an increase of just $28 million, based on a 9.2% ROE. An order is expected by yearend. Another AEP subsidiary, SWEPCO, asked the Texas commission for an increase of $83.1 million, based on an 11.25% ROE. Rates should go into effect in the first quarter of 2013.

The regulated operations are faring well. There is less regulatory activity than usual because most of AEP's utilities are earning their allowed ROEs, or are close to doing so. In addition, the company's transmission business should increase its contribution to the bottom line in the coming years, as there are plenty of opportunities to invest capital. Because the regulated picture is generally bright, we think the board of directors will raise the dividend in the fourth quarter, as it did in each of the past two years.

This stock's yield and 2015-2017 total return potential are similar to the utility norms.

Paul E. Debbas, CFA *September 21, 2012*

(A) Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '09, (1¢). '09 EPS don't add due to change in shs., '11 due to rounding. Next egs. due late Oct. (B) Div'ds historically paid early Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '11: $18.77/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.96%-10.9%; earned on avg. com. eq., '10: 9.3%. Regul. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

CLECO CORPORATION NYSE-CNL

RECENT PRICE	41.49	P/E RATIO	16.0 (Trailing: 14.5) (Median: 14.0)	RELATIVE P/E RATIO	1.05	DIV'D YLD	3.3%	VALUE LINE

TIMELINESS 3 Lowered 12/16/11

SAFETY 1 Raised 6/22/12

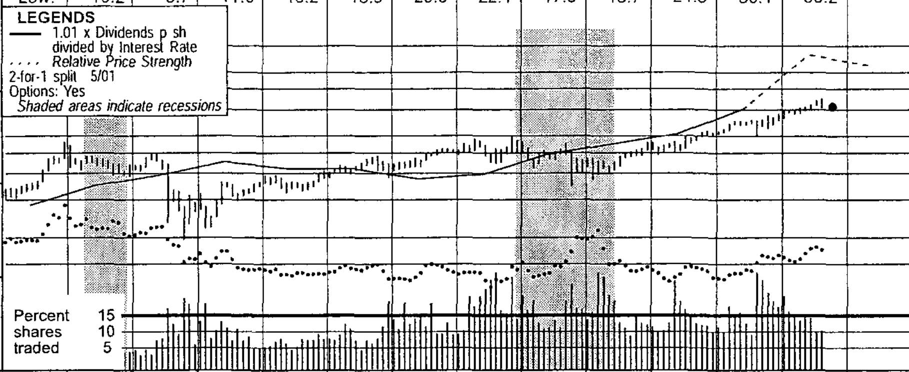
TECHNICAL 3 Raised 7/13/12

BETA .65 (1.00 = Market)

High:	27.3	24.9	18.4	20.8	24.4	26.2	29.8	28.4	28.1	31.8	38.3	45.3
Low:	19.2	9.7	11.0	16.2	18.9	20.5	22.1	17.3	18.7	24.3	30.1	36.2

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.01 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/01
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	40	(-5%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	0	2	2	0	0
to Sell	0	2	1	0	0	1	1	1	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	101	94	109
to Sell	91	108	74
Hld's(000)	42516	43902	43036

Percent shares traded 15 10 5

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	11.2
3 yr.	85.3	47.4
5 yr.	112.0	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.19	17.99	14.17	18.98	18.53	16.40	17.20	Revenues per sh	21.25
2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.63	2.69	3.71	3.78	5.12	5.28	5.20	5.30	"Cash Flow" per sh	6.50
1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.32	1.70	1.76	2.29	2.59	2.60	2.55	Earnings per sh A	3.25
.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	.90	.98	1.12	1.30	1.40	Div'd Decl'd per sh B ■ †	1.90
1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.51	5.59	4.15	4.68	3.25	3.95	2.15	Cap'l Spending per sh	2.25
8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.85	17.65	18.50	21.76	23.55	24.60	25.80	Book Value per sh C	30.25
44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	57.57	59.94	60.04	60.26	60.53	60.29	61.00	61.00	Common Shs Outst'g D	61.00
11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	19.6	14.1	13.2	12.3	13.3	Bold figures are		Avg Ann'l P/E Ratio	13.0
.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.93	1.04	.85	.88	.78	.84	Value Line		Relative P/E Ratio	.85
5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	3.5%	3.8%	3.9%	3.5%	3.3%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1332.9 mill. Due in 5 Yrs $209.9 mill.
LT Debt $1244.4 mill. LT Interest $75.9 mill.
Incl. $15.7 million capitalized leases.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $12.4 mill.
Pension Assets-12/11 $312.4 mill. Oblig. $362.0 mill.

Pfd Stock None

Common Stock 60,714,810 shs. as of 7/26/12

MARKET CAP: $2.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
721.2	874.6	745.8	920.2	1000.7	1030.6	1080.2	853.8	1148.7	1117.3	1000	1050	Revenues ($mill)	1300
74.2	61.2	66.1	75.0	74.7	79.6	102.1	106.3	139.5	157.8	160	160	Net Profit ($mill)	205
36.9%	37.2%	35.2%	39.2%	36.0%	24.3%	15.3%	8.3%	44.1%	30.6%	30.5%	30.5%	Income Tax Rate	30.5%
12.6%	5.8%	7.5%	4.3%	14.2%	57.9%	82.8%	93.5%	12.2%	4.3%	5.0%	3.0%	AFUDC % to Net Profit	2.0%
60.0%	64.4%	44.5%	46.3%	40.9%	43.2%	51.1%	54.2%	51.5%	48.5%	47.0%	46.0%	Long-Term Debt Ratio	42.0%
38.2%	33.8%	53.1%	52.0%	57.8%	56.7%	48.9%	45.8%	48.5%	51.5%	53.0%	54.0%	Common Equity Ratio	58.0%
1448.7	1408.5	1011.6	1315.9	1515.6	1780.5	2167.7	2436.4	2717.9	2756.9	2835	2910	Total Capital ($mill)	3175
1566.2	1417.1	1060.0	1188.7	1304.9	1725.9	2045.3	2247.0	2784.2	2893.9	2980	2945	Net Plant ($mill)	2775
7.1%	6.7%	8.9%	7.1%	6.3%	5.6%	6.1%	5.9%	6.6%	7.0%	7.0%	7.0%	Return on Total Cap'l	8.0%
12.8%	12.2%	11.8%	10.6%	8.3%	7.9%	9.6%	9.5%	10.6%	11.1%	10.5%	10.0%	Return on Shr. Equity	11.5%
13.1%	12.5%	11.9%	10.7%	8.3%	7.8%	9.6%	9.5%	10.6%	11.1%	10.5%	10.0%	Return on Com Equity E	11.5%
5.6%	3.5%	3.9%	4.1%	3.0%	2.6%	4.5%	4.7%	6.1%	6.3%	5.5%	4.5%	Retained to Com Eq	5.0%
58%	72%	68%	62%	65%	68%	53%	51%	42%	43%	50%	54%	All Div'ds to Net Prof	56%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.0	+5.9	+.4
Avg. Indust. Use (MWH)	3532	3657	3904
Avg. Indust. Revs. per KWH (¢)	6.48	7.68	7.58
Capacity at Peak (Mw)	2355	2559	2544
Peak Load, Summer (Mw)	2242	2348	2355
Annual Load Factor (%)	53.5	55.8	56.2
% Change Customers (avg.)	+.7	+.7	+.6
Fixed Charge Cov. (%)	138	294	415

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-1.5%	.5%	3.5%
"Cash Flow"	6.0%	12.5%	5.5%
Earnings	5.0%	10.0%	6.5%
Dividends	1.5%	2.0%	11.5%
Book Value	8.0%	10.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	213.0	207.2	241.5	192.1	853.8
2010	272.3	275.9	343.9	256.6	1148.7
2011	253.7	272.9	351.6	239.1	1117.3
2012	222.8	240.1	312.1	225	1000
2013	235	255	330	230	1050

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.11	.45	.99	.21	1.76
2010	.56	.58	.82	.33	2.29
2011	.48	.52	1.08	.51	2.59
2012	.50	.77	.98	.35	2.60
2013	.50	.60	1.10	.35	2.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.225	.225	.225	.225	.90
2009	.225	.225	.225	.225	.90
2010	.225	.25	.25	.25	.98
2011	.25	.28	.28	.3125	1.12
2012	.3125	.3125	.3375		

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 281,000 customers in central Louisiana. Through a subsidiary, has 775 megawatts of wholesale capacity. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 14%; other, 10%. Largest industrial customers are paper mills and other wood-product industries. Generating sources: coal & lignite, 34%; gas & oil, 29%; petroleum coke, 23%; purchased, 14%. Fuel costs: 40% of revenues. '11 reported deprec. rate (utility): 2.8%. Has 1,200 employees. Chairman: J. Patrick Garrett. President & CEO: Bruce A. Williamson. Inc.: Louisiana. Address: 2030 Donahue Ferry Road, P.O. Box 5000, Pineville, LA 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

Cleco's board of directors has raised the dividend again. This was the fourth increase since 2010, after a span of several years without a boost. The latest dividend hike was $0.025 a share (8%) quarterly. Cleco is targeting a payout ratio of 50%-60%. The company's cash flow is very healthy, giving the board the ability to continue raising the disbursement.

The utility is awaiting the outcome of a request for proposals (RFP). Most notably, the RFP includes a proposal to transfer Cleco's last nonregulated generating asset, the Coughlin gas-fired plant, to Cleco Power, its regulated utility subsidiary. (Cleco Power is now buying electricity from Coughlin under a three-year contract that began earlier this year.) The winning bidders, selected by an independent monitor, will probably be announced in late 2012. If the asset transfer is one of the winners, the Louisiana Public Service Commission and the Federal Energy Regulatory Commission would still have to approve it. This would probably occur in 2014.

We estimate that earnings will be about flat in 2012 and decline slightly in 2013. In the first half of 2012, Cleco booked $0.19 a share of income from the contractual expiration of indemnifications related to nonregulated generating units that were sold in 2010 and 2011. We *include* this income in our presentation, even though the company is excluding it from its earnings guidance of $2.34-$2.44 a share. We figure that, without any such income in 2013, profits will fall a bit. Beyond 2013, we aren't assuming that the aforementioned asset transfer will occur.

By utility standards, top-quality Cleco stock has a high valuation. The stock has outperformed most utility equities so far this year. Its dividend yield is about a percentage point below the industry average, and its price-earnings ratio is above the market multiple. The quotation is within our 2015-2017 Target Price Range, making total return potential low. In our view, the valuation reflects not only Cleco's strong dividend growth prospects, but some takeover speculation, as well. We don't advise investors to purchase this stock based on the possibility of an acquisition.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; '10, $1.91; '11, 63¢; losses from discont. ops.: '00, 14¢; '01, 4¢. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Feb., May, Aug. and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $10.61/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09: 11.7%; earned on avg. com. eq., '11: 11.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

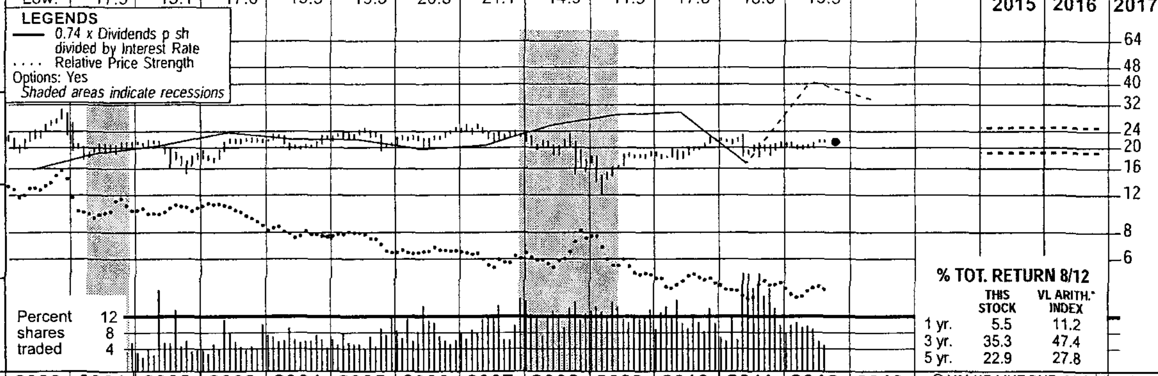
EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 21.41 | P/E RATIO 16.2 (Trailing: 16.6; Median: 17.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Lowered 2/17/12
SAFETY 2 Raised 3/23/12
TECHNICAL 3 Lowered 9/7/12
BETA .65 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	26.6	22.0	22.5	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	21.9
Low:	17.5	15.1	17.0	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5

LEGENDS
—— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+15%)	9%
Low	19	(-10%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	5	0	0	0	0
to Sell	0	0	1	0	1	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	54	50	50
to Sell	54	58	50
Hld's(000)	20129	20044	19674

Percent shares traded 12 8 4

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.5	11.2
3 yr.	35.3	47.4
5 yr.	22.9	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
12.53	12.83	14.02	13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.25	13.90	Revenues per sh	16.50
2.67	2.67	2.97	2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.90	3.20	"Cash Flow" per sh	4.00
1.23	1.29	1.53	1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.25	1.40	Earnings per sh A	1.75
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.00	Div'd Decl'd per sh B ■ †	1.20
3.79	3.38	3.03	4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.50	3.75	Cap'l Spending per sh	3.25
12.96	13.06	13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.75	17.15	Book Value per sh C	18.50
16.44	16.78	17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.25	42.50	Common Shs Outst'g D	43.25
14.8	13.9	14.0	21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	Bold figures are		Avg Ann'l P/E Ratio	12.5
.93	.80	.73	1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	1.00	Value Line		Relative P/E Ratio	.85
7.0%	7.1%	6.0%	5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	estimates		Avg Ann'l Div'd Yield	5.5%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $710.6 mill. Due in 5 Yrs $156.5 mill.
LT Debt $593.8 mill. LT Interest $36.2 mill.
Incl. $4.6 mill. capitalized leases.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-12/11 $141.0 mill. **Oblig.** $215.1 mill.
Pfd Stock None

Common Stock 42,328,967 shs. as of 8/1/12

MARKET CAP: $900 million (Small Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
305.9	325.5	325.5	386.2	413.5	490.2	518.2	497.2	541.3	576.9	560	590	Revenues ($mill)	710
25.5	29.5	21.8	23.8	39.9	33.2	39.7	41.3	47.4	55.0	53.0	59.0	Net Profit ($mill)	75.0
34.3%	34.5%	34.1%	33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	35.5%	35.5%	Income Tax Rate	35.5%
2.2%	1.0%	1.0%	2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	2.0%	2.0%	AFUDC % to Net Profit	1.0%
55.5%	52.0%	51.3%	51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	45.5%	49.0%	Long-Term Debt Ratio	49.5%
44.5%	48.0%	48.7%	49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	54.5%	51.0%	Common Equity Ratio	50.5%
740.3	789.2	779.1	803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1305	1425	Total Capital ($mill)	1600
794.1	833.9	857.0	896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1640	1725	Net Plant ($mill)	1925
5.4%	5.7%	4.7%	4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.5%	5.5%	Return on Total Cap'l	6.0%
7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.5%	8.0%	Return on Shr. Equity	9.0%
7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.5%	8.0%	Return on Com Equity E	9.0%
NMF	.1%	NMF	NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.5%	2.5%	Retained to Com Eq	3.0%
109%	99%	NMF	NMF	90%	117%	109%	109%	110%	49%	80%	72%	All Div'ds to Net Prof	70%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.3	+6.1	-2.3
Avg. Industrial Use (MWH)	2795	2813	2865
Avg. Industrial Rev/KWH (¢)	6.65	6.92	7.72
Capacity at Peak (Mw)	1257	1257	1392
Peak Load, Summer (Mw)	1085	1199	1198
Annual Load Factor (%)	55.4	53.2	52.0
% Change Customers (avg.)	+.2	+.4	-1.5
Fixed Charge Cov. (%)	201	248	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-.5%	-.5%	3.5%
"Cash Flow"	.5%	3.5%	5.5%
Earnings	2.0%	3.0%	6.0%
Dividends	-2.0%	-3.5%	2.0%
Book Value	1.5%	1.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	136.0	112.2	128.1	120.9	497.2
2010	139.9	114.5	154.1	132.8	541.3
2011	150.7	129.1	164.3	132.8	576.9
2012	137.1	131.6	156.3	135	560
2013	150	130	165	145	590

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.32	.22	.43	.22	1.18
2010	.22	.18	.55	.20	1.17
2011	.29	.22	.60	.21	1.31
2012	.23	.25	.55	.22	1.25
2013	.30	.25	.60	.25	1.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.32	.32	.32	.32	1.28
2009	.32	.32	.32	.32	1.28
2010	.32	.32	.32	.32	1.28
2011	.32	.32	--	--	.64
2012	.25	.25	.25		

BUSINESS: The Empire District Electric Company supplies electricity to 166,000 customers in a 10,000 sq. mi. area in Missouri (89% of '11 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acquired Missouri Gas (43,000 customers) 6/06. Supplies water service and has a small fiber-optics operation. Electric revenue breakdown: residential, 43%; commercial, 30%; industrial, 15%; other, 12%. Generating sources: coal, 45%; gas, 24%; hydro, 1%; purchased, 30%. Fuel costs: 42% of revenues. '11 reported deprec. rate: 2.9%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: Kansas. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, Missouri 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric has filed an electric rate case in Missouri. The utility is seeking a base rate increase of $30.7 million (7.6%), based on a return on equity of 10.6%. Empire District asked the state commission for an interim tariff hike of $6.2 million (for costs associated with the tornado that hit Joplin in May of 2011) that would have taken effect 30 days after the filing, which occurred on July 6th, but the regulators turned down the request. (Whether they will grant interim rate relief at some point is to be determined.) An order is due 11 months after the filing. Separately, the utility is asking for a water rate increase of $516,400 (29.6%), since it hasn't had a rate boost since 2006. A ruling is likely by yearend.

We have raised our 2012 earnings estimate by a nickel a share, to $1.25. That's because favorable weather conditions helped lift June-quarter results. Our revised estimate is near the upper end of management's targeted range of $1.13-$1.27 a share.

The service area continues to recover from the aforementioned tornado. Immediately after the tornado hit Joplin, some 8,000 customers had lost their homes or businesses. This figure fell to 1,800 as of yearend, and 1,100 as of mid-2012. Electricity usage from FEMA trailers and hotels that were more full than usual (thanks to relief workers) offset part of the lost revenues. Some large customers won't complete their rebuilding until next year or even 2014, however.

We estimate that earnings will advance to $1.40 a share in 2013. We assume that the rate order in Missouri is reasonable, and that additional customers return to service. If our forecast is correct, Empire District will attain its highest share profits since 2006, and its second-highest since 1998. However, we expect no dividend increase until 2014 because the payout ratio is on the high side.

This stock's dividend yield is fractionally above the utility average. Dividend growth potential over the next 3 to 5 years is low, however, and total return prospects over that time frame are only average for this industry. This equity is best suited for investors seeking a high current yield.

Paul E. Debbas, CFA *September 21, 2012*

(A) Excl. loss from discont. ops.: '06, 2¢. '09 & '11 EPS don't add due to rounding, '10 due to change in shs. Next earnings report due late Oct. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan available (3% discount). † Shareholder investment plan available. (C) Incl. intangibles. In '11: $6.69/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '10: none specified; earned on avg. com. eq., '11: 8.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	80

ENTERGY CORP. NYSE-ETR

RECENT PRICE 67.76 | P/E RATIO 12.1 (Trailing: 9.9 / Median: 14.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 3 Lowered 2/10/12

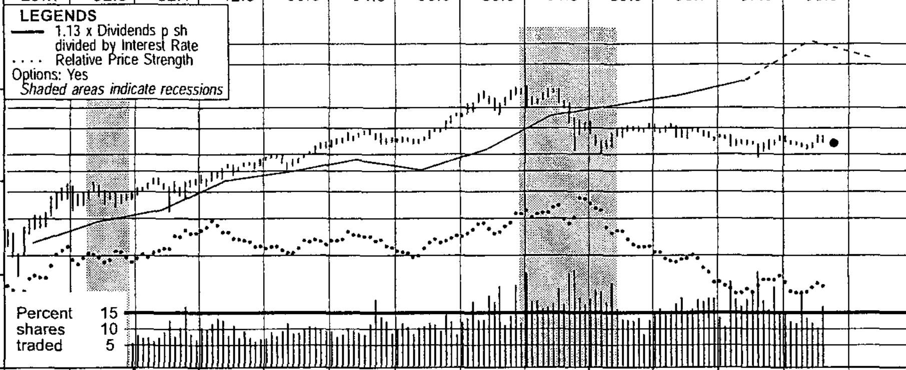
SAFETY 2 New 12/26/08

TECHNICAL 2 Raised 8/31/12

BETA .70 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	44.7	46.8	57.2	68.7	79.2	94.0	125.0	127.5	86.6	84.3	74.5	74.5		
Low:	32.6	32.1	42.3	50.6	64.5	66.8	89.6	61.9	59.9	68.7	57.6	63.0		

LEGENDS
— 1.13 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+25%)	10%
Low	60	(-10%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	5	1	1	1	2
to Sell	1	0	0	0	5	1	1	1	2

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	223	224	210
to Sell	197	212	213
Hld's(000)	142805	140958	134550

Percent shares traded 15 10 5

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.6	11.2
3 yr.	-1.2	47.4
5 yr.	-19.5	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
30.75	38.89	46.57	35.51	45.61	43.59	37.34	40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	58.20	60.55	Revenues per sh	67.25
5.84	6.20	6.11	5.06	6.49	6.41	7.62	7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	15.35	15.45	"Cash Flow" per sh	17.00
2.48	2.25	2.22	2.25	2.97	3.08	3.68	3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	5.20	4.45	Earnings per sh A	5.00
1.80	1.80	1.50	1.20	1.22	1.28	1.34	1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	Div'd Decl'd per sh B ■ †	3.40
2.45	3.45	4.63	4.84	6.80	6.25	6.88	6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	14.05	12.30	Cap'l Spending per sh	12.50
28.51	27.23	28.79	28.81	31.89	33.78	35.24	38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.30	52.25	Book Value per sh C	56.75
232.96	245.84	246.83	247.08	219.60	220.73	222.42	228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.00	171.00	Common Shs Outst'g D	171.00
11.1	11.6	12.9	13.2	10.1	12.5	11.5	13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.5
.70	.67	.67	.75	.66	.64	.63	.79	.80	.87	.77	1.02	1.00	.80	.74	.57	estimates		Relative P/E Ratio	.95
6.5%	6.9%	5.2%	4.1%	4.1%	3.3%	3.2%	3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%			Avg Ann'l Div'd Yield	4.7%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $12533 mill. **Due in 5 Yrs** $2479.0 mill.
LT Debt $12005 mill. **LT Interest** $540.0 mill.
Incl. $1020 mill. of securitization bonds.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $84.9 mill.
Pension Assets-12/11 $3.40 bill. **Oblig.** $5.19 bill.
Pfd Stock $280.5 mill. **Pfd Div'd** $20.0 mill.
6,115,105 shs. $4.20 to $7.88, $100 par; 1,000,000 shs. 11.50%, all without sinking fund.
Common Stock 177,319,259 shs. as of 7/31/12
MARKET CAP: $12 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
8305.0	9195.0	10124	10106	10932	11484	13094	10746	11488	11229	10300	10350	Revenues ($mill)	11500
878.4	874.2	933.1	943.1	1160.9	1160.0	1240.5	1251.1	1270.3	1367.4	940	805	Net Profit ($mill)	905
25.1%	35.9%	28.2%	37.2%	27.6%	30.7%	32.7%	33.6%	32.7%	17.3%	18.5%	34.0%	Income Tax Rate	34.0%
6.4%	8.7%	7.0%	8.0%	5.5%	5.8%	5.6%	7.4%	7.4%	8.9%	15.0%	14.0%	AFUDC % to Net Profit	12.0%
45.7%	44.8%	44.7%	51.9%	51.2%	54.3%	58.2%	55.3%	56.3%	52.2%	53.5%	55.0%	Long-Term Debt Ratio	57.5%
50.6%	53.2%	52.9%	45.5%	46.7%	43.9%	40.2%	43.1%	42.1%	46.4%	45.5%	43.5%	Common Equity Ratio	41.0%
15499	16361	15696	17013	17539	17902	19795	19985	20166	19324	20050	20550	Total Capital ($mill)	23600
17195	18299	18696	19197	19438	20974	22429	23389	23848	25609	26350	26650	Net Plant ($mill)	27200
7.3%	6.8%	7.4%	6.8%	8.0%	7.9%	7.5%	7.6%	7.7%	8.5%	6.0%	5.5%	Return on Total Cap'l	5.5%
10.4%	9.7%	10.8%	11.5%	13.6%	14.2%	15.0%	14.0%	14.4%	14.8%	10.0%	8.5%	Return on Shr. Equity	9.0%
10.9%	9.8%	11.0%	11.9%	13.8%	14.4%	15.3%	14.3%	14.7%	15.0%	10.0%	9.0%	Return on Com Equity E	9.0%
7.1%	5.6%	5.8%	6.0%	8.3%	8.0%	8.1%	7.6%	7.6%	8.4%	3.5%	2.5%	Retained to Com Eq	3.0%
37%	44%	48%	51%	41%	46%	48%	48%	49%	45%	64%	74%	All Div'ds to Net Prof	66%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.5	+8.4	+1.1
Avg. Indust. Use (MWH)	874	936	991
Avg. Indust. Revs. per KWH(¢)	5.60	5.70	5.65
Capacity at Peak (Mw)	23578	24310	23979
Peak Load, Summer (Mw)	21009	21799	22387
Annual Load Factor (%)	60.0	62.0	60.0
% Change Customers (yr-end)	+1.1	+.9	+.5
Fixed Charge Cov. (%)	355	342	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.0%	4.5%	1.5%
"Cash Flow"	10.0%	11.5%	1.0%
Earnings	9.5%	8.5%	-5.0%
Dividends	10.0%	9.0%	1.0%
Book Value	4.5%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2789	2521	2937	2499	10746
2010	2760	2863	3332	2533	11488
2011	2541	2803	3396	2489	11229
2012	2384	2519	3000	2397	10300
2013	2450	2500	3000	2400	10350

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.20	1.14	2.32	1.64	6.30
2010	1.12	1.65	2.62	1.26	6.66
2011	1.38	1.76	3.53	.87	7.55
2012	.40	2.06	2.00	.74	5.20
2013	.80	1.25	1.60	.80	4.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.75	.75	.75	.75	3.00
2009	.75	.75	.75	.75	3.00
2010	.75	.83	.83	.83	3.24
2011	.83	.83	.83	.83	3.32
2012	.83	.83	.83		

BUSINESS: Entergy Corporation supplies electricity to 2.7 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans. Distributes gas to 191,000 customers in Louisiana. Has a nonutility nuclear subsidiary that owns six units. Electric revenue breakdown: residential, 39%; commercial, 26%; industrial, 25%; other, 10%. Generating sources: nuclear, 34%; gas, 25%; coal, 13%; purchased, 28%. Fuel costs: 36% of revenues. '11 reported depreciation rate: 2.6%. Has 14,700 employees. Chairman & CEO: J. Wayne Leonard. President & COO: Richard J. Smith. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy has taken the first steps toward the intended sale of its transmission assets to ITC Holdings. The companies have applied for approval in Louisiana and New Orleans (which has a separate commission), and filings with the regulators in Texas, Arkansas, and the Federal Energy Regulatory Commission will probably happen in the coming weeks. Entergy decided to sell its transmission system because this business is capital-intensive and makes up less than 10% of its assets. The company would receive $1.775 billion in cash, which it would use for debt reduction. In order to make the deal tax-free, ITC would issue enough stock to Entergy shareholders so that they would own 50.1% of ITC. ITC's stockholders must approve the transaction.

Entergy has nuclear worries. In New York, the company's license extension applications with the Nuclear Regulatory Commission for the Indian Point units have been delayed. The licenses expire in 2013 and 2015, but Entergy believes the plants may keep running while the filings are pending. The company is also embroiled in a dispute with the state, which wants it to build cooling towers at the site. Entergy is proposing a much less costly alternative. In Vermont, litigation between the state government and Entergy concerning Vermont Yankee is ongoing. In Michigan, the NRC is conducting supplemental inspections of Palisades, which has had operating problems.

We have raised our 2012 earnings estimate. Second-quarter profits exceeded our expectation thanks to a tax benefit that boosted the bottom line by $0.44 a share. Nevertheless, earnings will probably wind up below the 2012 tally due to low prices in the power markets, less favorable weather conditions than in 2011, and expenses associated with the asset sale to ITC. Assuming a more normal tax rate in 2013, earnings will probably decline.

This stock stands out for its dividend yield, which is above the utility average. The low valuation reflects the market's concerns about the state of the power markets and the aforementioned nuclear troubles. Even so, we think this issue is suitable for most utility accounts, except those stressing dividend growth.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '97, ($1.22); '98, 78¢; '01, 15¢; '02, ($1.04); '03, 33¢ net; '05, (21¢); '12, ($1.26). '10 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '11: $34.05/sh. (D) In mill. (E) Rate base: net orig. cost. Allowed return on equity (blended): 10.5%; earned on avg. com. eq., '11: 15.4%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

GREAT PLAINS EN'GY NYSE-GXP

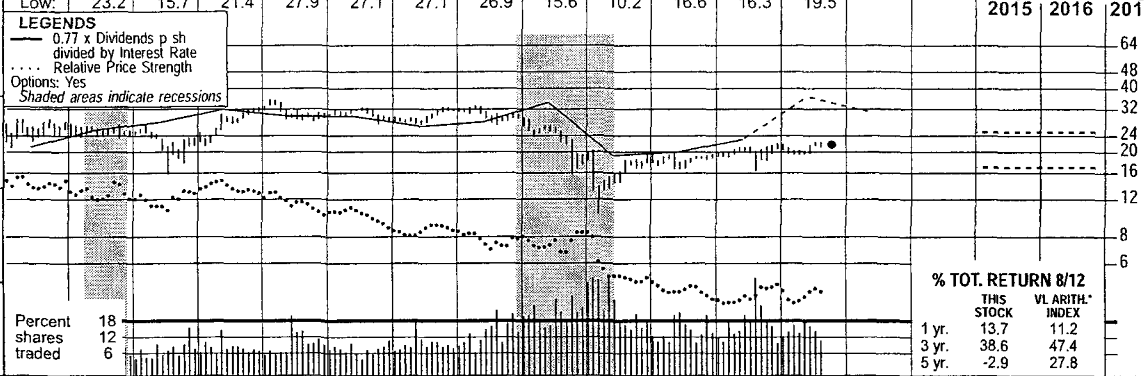
RECENT PRICE	21.76	P/E RATIO	14.3 (Trailing: 17.3 / Median: 15.0)	RELATIVE P/E RATIO	0.94	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Lowered 3/9/12
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Raised 8/10/12
BETA .75 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	27.6	27.0	32.8	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.5
Low:	23.2	15.7	21.4	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5

Target Price Range
2015 | 2016 | 2017

LEGENDS
— 0.77 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+15%)	7%
Low	17	(-20%)	-1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	115	105	114
to Sell	110	116	106
Hld's(000)	94551	102697	107362

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.7	11.2
3 yr.	38.6	47.4
5 yr.	-2.9	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
14.60	14.47	15.17	14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	*15.65*	*16.30*	Revenues per sh	*19.50*
3.90	3.91	4.21	3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	*3.45*	*3.70*	"Cash Flow" per sh	*4.75*
1.69	1.69	1.89	1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	*1.35*	*1.40*	Earnings per sh A	*1.75*
1.59	1.62	1.64	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	*.86*	*.88*	Div'd Decl'd per sh B ■	*1.10*
1.66	2.05	1.97	2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	*4.15*	*5.15*	Cap'l Spending per sh	*4.00*
14.71	14.19	14.41	13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	*21.70*	*22.20*	Book Value per sh C	*24.00*
61.91	61.91	61.91	61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	*153.50*	*153.50*	Common Shs Outst'g D	*153.50*
15.9	17.0	15.7	20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	Bold figures are		Avg Ann'l P/E Ratio	*12.0*
1.00	.98	.82	1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.02	Value Line		Relative P/E Ratio	*.80*
5.9%	5.6%	5.5%	6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	estimates		Avg Ann'l Div'd Yield	*5.3%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $3804.5 mill. **Due in 5 Yrs** $1079.6 mill.
LT Debt $3013.4 mill. **LT Interest** $172.3 mill.
(LT interest earned: 2.2x)

Leases, Uncapitalized Annual rentals $19.7 mill.
Pension Assets-12/11 $591.1 mill.
Oblig. $980.6 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 153,430,889 shs.
as of 8/6/12
MARKET CAP: $3.3 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1861.9	2149.5	2464.0	2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	*2400*	*2500*	Revenues ($mill)	*3000*
129.2	159.0	178.8	164.2	127.6	159.2	119.5	135.6	211.7	174.4	*205*	*215*	Net Profit ($mill)	*280*
27.2%	34.2%	24.1%	18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
1.0%	1.8%	2.0%	2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	*1.0%*	*5.0%*	AFUDC % to Net Profit	*2.0%*
53.5%	53.8%	44.8%	47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	*47.0%*	*48.5%*	Long-Term Debt Ratio	*44.5%*
44.7%	44.4%	53.4%	50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	*52.5%*	*51.0%*	Common Equity Ratio	*55.0%*
2102.8	2154.6	2137.1	2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	*6345*	*6700*	Total Capital ($mill)	*6700*
2604.1	2700.9	2734.5	2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	*7365*	*7810*	Net Plant ($mill)	*8475*
7.7%	9.0%	10.1%	8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	4.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
13.2%	16.0%	15.1%	13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	*6.0%*	*6.5%*	Return on Shr. Equity	*7.5%*
13.6%	16.4%	15.5%	13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	*6.0%*	*6.5%*	Return on Com Equity E	*7.5%*
2.3%	4.4%	5.1%	3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
83%	73%	68%	76%	104%	91%	NMF	81%	54%	66%	*62%*	*63%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	+18.1	+5.6	-1.7
Avg. Indust. Use (MWH)	1367	1429	1463
Avg. Indust. Revs. per KWH (¢)	5.47	5.89	6.11
Capacity at Peak (Mw)	6336	6272	6697
Peak Load, Summer (Mw)	5347	5531	5690
Annual Load Factor (%)	51.3	52.8	50.5
% Change Customers (avg.)	-1.2	+.2	--
Fixed Charge Cov. (%)	144	218	211

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-1.5%	-14.0%	*3.5%*
"Cash Flow"	-1.5%	-3.5%	*4.5%*
Earnings	-2.5%	-9.5%	*5.5%*
Dividends	-6.5%	-13.0%	*5.0%*
Book Value	4.5%	5.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	419.2	480.5	587.7	477.6	1965.0
2010	506.9	552.0	728.8	467.8	2255.5
2011	492.9	565.1	773.7	486.3	2318.0
2012	479.7	603.6	*816.7*	*500*	*2400*
2013	*550*	*600*	*800*	*550*	*2500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.05	.28	.57	.10	1.03
2010	.15	.47	.96	d.04	1.53
2011	.01	.31	.91	.01	1.25
2012	d.07	.41	*.91*	*.10*	*1.35*
2013	*.10*	*.30*	*.90*	*.10*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.415	.415	.415	.415	1.66
2009	.2075	.2075	.2075	.2075	.83
2010	.2075	.2075	.2075	.2075	.83
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125		

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 824,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 41%; commercial, 38%; industrial, 8%; other, 13%. Generating sources: coal, 71%; nuclear, 11%; wind, 2%; gas & oil, 1%; purchased, 15%. Fuel costs: 30% of revs. '11 reported deprec. rate (utility): 3.0%. Has 3,100 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, MO 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

As usual, Great Plains Energy's utility subsidiaries have rate cases pending. The company's utilities have not been earning their allowed returns on equity in recent years, so they have been filing rate applications frequently in order to reduce the effects of regulatory lag and weak volume. Great Plains' utilities asked the Missouri commission for tariff hikes totaling $189.2 million, based on a return of 10.4% on a 52.5% common-equity ratio. The company is also asking the state regulators to grant it tracking mechanisms to recover rising property taxes and earn a return on transmission expenditures. New rates are expected to go into effect in late January. Kansas City Power & Light asked the Kansas commission for a rate increase of $63.6 million, based on a 10.4% return on a 51.8% common-equity ratio. New tariffs are expected to take effect at the start of 2013. Even if the utilities receive reasonable rate orders, they are likely to under-earn their allowed ROEs again next year.

We have raised our 2012 earnings estimate by $0.15 a share, to $1.35. Favorable weather conditions helped lift June-period results, and the higher-than-normal temperatures continued into the third quarter. Our revised estimate is still within management's targeted range of $1.20-$1.40.

We look for only a moderate share-earnings increase in 2013. We assume reasonable regulatory treatment, but we also base our forecast on a return to *normal* weather patterns. Also, average shares outstanding will be higher due to the 17.1 million shares that Great Plains issued in June of 2012 for the conversion of some debt into equity.

The Wolf Creek nuclear unit has room for improvement. The plant, 47%-owned by KCP&L, had a refueling outage in 2011 that was much longer than expected, and then had an unplanned outage in the first quarter of 2012. Its next refueling outage is scheduled for the first quarter of 2013.

***We are not enthusiastic about this* stock.** The yield (even assuming a dividend hike in the fourth quarter) is only about equal to the utility average, and with the quotation well within our 2015-2017 Target Price Range, total return potential is unimpressive.

Paul E. Debbas, CFA *September 21, 2012*

(A) Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on discont. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢; '09, (1¢). '09-'11 EPS don't add due to change in shares or rounding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '11: $9.01/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '11: 10%; in KS in '10: 10%; earned on avg. com. eq., '11: 6.0%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	5
Earnings Predictability	70

HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
25.77	15.8	(Trailing: 15.5) (Median: 19.0)	1.04	4.8%	VALUE LINE

TIMELINESS 3 Lowered 10/12/12

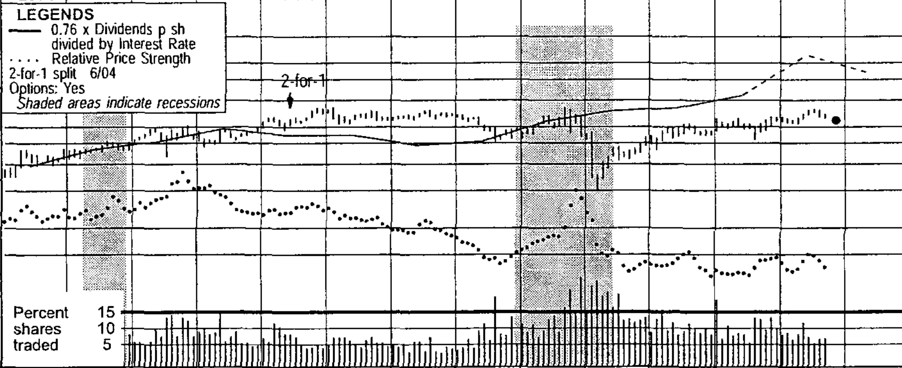
SAFETY 2 Raised 11/2/12

TECHNICAL 2 Raised 10/19/12

BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8	22.7	25.0	26.8	29.2
Low:	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0	12.1	18.6	20.6	24.7

LEGENDS
—— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/04
Options: Yes
Shaded areas indicate recessions



Target Price Range

	2015	2016	2017

64
48
40
32
24
20
16
12
8
6

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	*8%*
Low	25	(-5%)	*4%*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	1	0	0	1	0	0	0	1	0
Options	1	0	0	0	0	0	0	0	0
to Sell	1	0	0	1	2	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	102	93	89
to Sell	73	77	79
Hld's(000)	34567	35033	33643

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.6	28.2
3 yr.	69.9	42.3
5 yr.	59.9	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	***34.70***	***33.15***	Revenues per sh	***32.00***
2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	***3.40***	***3.40***	"Cash Flow" per sh	***3.75***
1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	***1.60***	***1.70***	Earnings per sh A	***2.00***
1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	***1.24***	***1.24***	Div'd Decl'd per sh B ■ †	***1.40***
3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	***3.55***	***4.15***	Cap'l Spending per sh	***7.50***
12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	***16.45***	***17.40***	Book Value per sh C	***20.25***
61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	***98.00***	***104.00***	Common Shs Outst'g D	***122.00***
13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	*Bold figures are*		Avg Ann'l P/E Ratio	***13.5***
.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	1.08	*Value*	*Line*	Relative P/E Ratio	***.90***
6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	*estimates*		Avg Ann'l Div'd Yield	***5.1%***

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1429.7 mill. **Due in 5 Yrs** $369.8 mill.
LT Debt $1282.6 mill. **LT Interest** $66.7 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 4.2x)
Pension Assets-12/11 $839.6 mill.
Oblig. $1.32 bill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 97,082,085 shs.
as of 7/23/12
MARKET CAP: $2.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	3218.9	2309.6	2665.0	3242.3	***3400***	***3450***	Revenues ($mill)	***3900***
120.2	120.1	109.6	120.3	109.9	93.6	92.2	84.9	115.4	140.1	***160***	***175***	Net Profit ($mill)	***250***
34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	34.7%	34.1%	37.0%	35.1%	***35.0%***	***34.0%***	Income Tax Rate	***29.0%***
4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	14.2%	20.6%	7.4%	6.0%	***5.0%***	***7.0%***	AFUDC % to Net Profit	***43.0%***
52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	46.0%	48.0%	44.5%	44.9%	***45.5%***	***40.5%***	Long-Term Debt Ratio	***45.0%***
46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	52.7%	50.7%	54.3%	53.9%	***53.5%***	***58.5%***	Common Equity Ratio	***54.0%***
2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	2635.2	2840.8	2732.9	2841.3	***3020***	***3105***	Total Capital ($mill)	***4575***
2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	2907.4	3088.6	3165.9	3334.5	***3505***	***3750***	Net Plant ($mill)	***5525***
7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	4.7%	4.3%	5.6%	6.2%	***6.5%***	***6.5%***	Return on Total Cap'l	***6.5%***
11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	6.5%	5.8%	7.6%	8.9%	***9.5%***	***9.5%***	Return on Shr. Equity	***10.0%***
11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	5.8%	7.7%	9.0%	***10.0%***	***9.5%***	Return on Com Equity E	***10.0%***
4.3%	3.9%	1.1%	1.5%	.7%	.8%	.5%	NMF	1.4%	2.1%	***2.5%***	***2.5%***	Retained to Com Eq	***3.5%***
63%	64%	87%	85%	93%	89%	93%	116%	82%	78%	***77%***	***73%***	All Div'ds to Net Prof F	***67%***

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.5	-1.1	-.5
Avg. Indust. Use (MWH)	6403	6352	6284
Avg. Indust. Revs. per KWH (¢)	17.68	21.41	27.89
Capacity at Yearend (Mw)	2347	2325	2327
Peak Load, Winter (Mw)	1618	1562	1530
Annual Load Factor (%)	72.2	73.9	74.8
% Change Customers (yr-end)	+.5	+.5	+.3
Fixed Charge Cov. (%)	234	300	337

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '09-'11 to '15-'17**
Revenues	1.5%	1.5%	*1.5%*
"Cash Flow"	-1.0%	-2.0%	*4.5%*
Earnings	-2.0%	-3.0%	*9.0%*
Dividends	--	--	*2.0%*
Book Value	2.0%	1.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	543.8	525.9	620.3	619.6	2309.6
2010	619.0	655.7	694.6	695.7	2665.0
2011	710.6	794.3	886.4	851.0	3242.3
2012	814.9	854.3	***880.8***	***850***	***3400***
2013	***850***	***850***	***900***	***850***	***3450***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.22	.17	.37	.15	.91
2010	.29	.31	.35	.26	1.21
2011	.30	.28	.50	.36	1.44
2012	.40	.40	***.45***	***.35***	***1.60***
2013	***.43***	***.40***	***.50***	***.37***	***1.70***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.31	.31	.31	.31	1.24
2009	.31	.31	.31	.31	1.24
2010	.31	.31	.31	.31	1.24
2011	.31	.31	.31	.31	1.24
2012	.31	.31	.31		

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 446,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Disc. int'l power sub. in '01. Elec. rev. breakdown: res'l, 33%; comm'l, 34%; large light & power, 32%; other, 1%. Generating sources: oil, 60%; purchased, 40%. Fuel costs: 60% of revs. '11 reported depr. rate (util.): 3.2%. Has 3,700 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 900 Richards St., P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

One of Hawaiian Electric Industries' electric utility subsidiaries has filed a general rate case. Hawaii Electric Light Company (HELCO) is seeking a tariff hike of $19.8 million (4.2%), based on a return of 10.25% on a common-equity ratio of 57.05%. An interim rate order is expected in July of 2013.

HEI's three utilities are earning improved returns on equity. As of mid-2012, their consolidated ROE for the trailing 12 months was 8.73%, compared with just 5.83% a year earlier. A key reason is a new regulatory mechanism under which each utility is operating. The new regulation decoupled electric revenues and volume and provided for recovery of plant additions and rises in operating and maintenance expenses through a revenue adjustment mechanism. This is partly why we have raised the company's Financial Strength rating and the stock's Safety rank a notch each. However, the new mechanisms don't cover everything, and there is a five-month lag (June 1st, instead of January 1st) before the utilities start recovering these items. This is why each utility is still falling well short of earning its allowed ROE of 10.0%.

Profits at American Savings Bank will probably decline slightly in 2012. The interest-rate margin is being squeezed—something thrifts are experiencing in this environment of very low interest rates—and fee income is lower, as well. Even so, there are some positive factors. ASB has experienced seven consecutive quarters of loan growth, and with the state's economy recovering, the provision for loan losses and net loan charge-offs are declining.

We expect increased earnings in 2012 and 2013. The effect of the utilities' improved ROEs is being seen in HEI's bottom line. Higher utility income should outweigh the aforementioned drop in ASB's earnings this year. Interim rate relief at HELCO should help in 2013.

We regard HEI stock as an average utility choice. On the positive side, the dividend yield is fractionally above the industry average. On the negative side, due to the high payout ratio, we think it will be a few more years before the board of directors raises the dividend. Thus, 3- to 5-year total return potential is mediocre.

Paul E. Debbas, CFA *November 2, 2012*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due early Nov. (B) Div'ds histor. paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '11: $7.83/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '11: HECO, 10%; in '12: HELCO, 10%; in '12: MECO, 10%; earned on avg. com. eq., '11: 9.2%. Regul. Climate: Avg. (F) Excl. div'ds paid through reinvest. plan.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	70

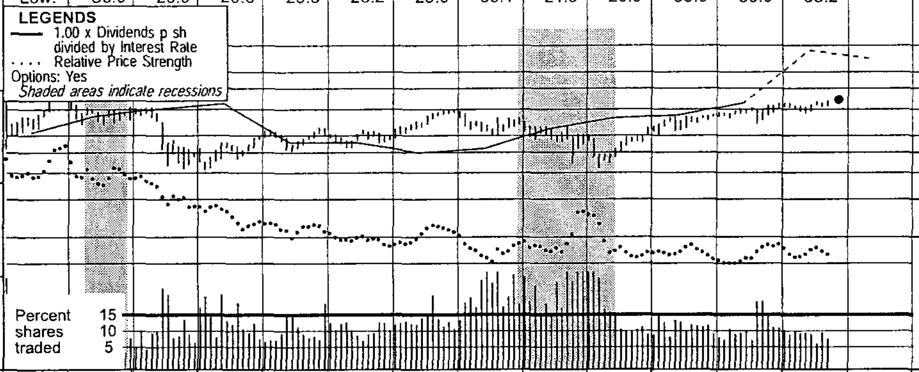
IDACORP, INC. NYSE-IDA

RECENT PRICE	44.46	P/E RATIO	13.3 (Trailing: 12.5 / Median: 15.0)	RELATIVE P/E RATIO	0.87	DIV'D YLD	3.4%	VALUE LINE

TIMELINESS 3 Lowered 5/14/10
SAFETY 3 Lowered 2/14/03
TECHNICAL 3 Lowered 9/28/12
BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	49.4	41.0	30.2	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.0
Low:	33.6	20.9	20.6	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	35	(-20%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	1	0	0	0
Options	9	0	0	0	0	0	0	0	0
to Sell	9	0	1	2	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	78	84	86
to Sell	77	73	69
Hld's(000)	34282	34810	35043

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.2	28.2
3 yr.	66.1	42.3
5 yr.	58.5	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.38	19.90	29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	**23.00**	**23.50**	Revenues per sh	**24.55**
4.05	4.22	4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	**5.90**	**6.00**	"Cash Flow" per sh	**6.40**
2.21	2.32	2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	**3.30**	**3.25**	Earnings per sh A	**3.40**
1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	**1.37**	**1.52**	Div'd Decl'd per sh B† ■	**1.90**
2.49	2.51	2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	**4.70**	**5.00**	Cap'l Spending per sh	**7.55**
18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	**35.10**	**36.80**	Book Value per sh C	**39.35**
37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	**50.00**	**50.00**	Common Shs Outst'g D	**53.00**
13.7	13.6	14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**13.0**
.86	.78	.75	.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.73			Relative P/E Ratio	**.85**
6.1%	5.9%	5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%			Avg Ann'l Div'd Yield	**4.2%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt \$1537.6 mill. **Due in 5 Yrs** \$175.3 mill.
LT Debt \$1536.5 mill. **LT Interest** \$70.0 mill.
(LT interest earned: 2.5x)

Pension Assets-12/11 \$390.1 mill. **Oblig.** \$655.4 mill.

Pfd Stock None

Common Stock 50,154,714 shs. **as of 7/27/12**

MARKET CAP: \$2.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
928.8	782.7	844.5	859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	**1150**	**1175**	Revenues (\$mill)	**1300**
66.3	40.1	77.8	63.7	100.1	82.3	98.4	124.4	142.5	166.9	**165**	**160**	Net Profit (\$mill)	**180**
--	--	--	16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	**25.0%**	**30.0%**	Income Tax Rate	**30.0%**
3.0%	7.5%	3.9%	4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	**25.0%**	**25.0%**	AFUDC % to Net Profit	**30.0%**
49.2%	50.8%	49.3%	50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	**46.0%**	**46.5%**	Long-Term Debt Ratio	**47.5%**
47.9%	46.4%	50.7%	50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	**54.0%**	**53.5%**	Common Equity Ratio	**52.5%**
1826.9	1862.5	1987.8	2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	**3255**	**3430**	Total Capital (\$mill)	**4000**
1906.5	2088.3	2209.5	2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	**3680**	**3975**	Net Plant (\$mill)	**5000**
5.1%	3.7%	5.3%	4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	**6.0%**	**6.0%**	Return on Total Cap'l	**5.5%**
7.1%	4.4%	7.7%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	**9.5%**	**8.5%**	Return on Shr. Equity	**8.5%**
7.0%	4.2%	7.2%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	**9.5%**	**8.5%**	Return on Com Equity E	**8.5%**
NMF	NMF	2.7%	1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	**5.5%**	**4.5%**	Retained to Com Eq	**4.0%**
113%	NMF	65%	80%	51%	64%	55%	46%	41%	36%	**42%**	**48%**	All Div'ds to Net Prof	**56%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.1	-3.1	+1.6
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.51	4.50	4.54
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3014	2714	2973
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.6	+.4	+.7
Fixed Charge Cov. (%)	280	264	230

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-10.5%	.5%	2.5%
"Cash Flow"	--	5.0%	3.0%
Earnings	-.5%	8.5%	2.0%
Dividends	-4.5%	--	8.0%
Book Value	3.5%	5.0%	4.0%

Cal-endar	QUARTERLY REVENUES(\$ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	228.6	243.6	324.5	253.1	1049.8
2010	252.5	241.8	309.4	232.3	1036.0
2011	251.5	235.0	309.6	230.7	1026.8
2012	241.1	254.7	**370**	**284.2**	**1150**
2013	**275**	**260**	**360**	**280**	**1175**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.40	.59	1.16	.49	2.64
2010	.34	.82	1.39	.40	2.95
2011	.60	.42	2.16	.18	3.36
2012	.50	.71	**1.54**	**.55**	**3.30**
2013	**.55**	**.60**	**1.60**	**.50**	**3.25**

Cal-endar	QUARTERLY DIVIDENDS PAID B†■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.30	.30	.30	.30	1.20
2009	.30	.30	.30	.30	1.20
2010	.30	.30	.30	.30	1.20
2011	.30	.30	.30	.30	1.20
2012	.33	.33	.33	.38	

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 2 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles with estimated population of one million. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 39%; commercial, 21%; industrial, 13%; other, 27%. Fuel sources: hydro, 59%; thermal, 27%; purchased power, 14%. '11 depreciation rate: 2.4%. Has 2,058 employees. Chairman: Gary G. Michael. President & CEO: J. LaMont Keen. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, ID. 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP posted strong second-quarter profit comparisons. Earnings advanced nearly 70% over the year-earlier figure, to \$0.71 a share. Indeed, the impressive results can be attributed to increasing energy sales, coupled with rising sales and higher retail base rates. Notably, sales from irrigation customers practically doubled, compared to last year, due to warmer temperatures and lower precipitation levels.

Management raised its guidance for 2012. Share earnings are now forecasted to reach between \$3.20 and \$3.35, largely due to better-than-expected second-quarter results. Thus, we have increased our estimate for 2012 by \$0.30 a share, to \$3.30. *(Subscribers should note that September-period earnings were scheduled to be released after we rolled the presses on this Issue.)* What's more, IDA expects to exceed a minimum return of 9.5% without the use of additional accumulated deferred investment tax credits (ADITCs), and revised its estimate down from the \$5 million previously forecasted. In fact, during the second quarter, the company reversed the \$0.8 million used during the March-period.

In other news, its Boardman to Hemingway (B2H) project has hit a roadblock. The service date of the Boardman (Oregon) to Hemingway (Idaho) transmission line has been delayed due to governmental and environmental headwinds. It is now expected to be completed no earlier than 2018, versus the previous target of 2016.

The board of directors increased the dividend approximately 15%, to \$0.38 a share (payable November 30th). Indeed, this will be the second dividend increase in 2012, and the first at yearend since 2004. We expect further improvement on this front, as the company intends to boost its dividend payout ratio to be between 50% and 60% of net profit over the long-term.

Income-seeking accounts may want to look elsewhere. Despite the rising dividend, the 3.4% yield remains below the utility industry average. However, investors should keep in mind that we do expect the measure to become more comparable to its industry peers over the long term.

Michelle Jensen *November 2, 2012*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early March, late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '11: \$20.74/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '08: 10.5%; earned on avg. system com. eq., '11: 10.1%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	85

NV ENERGY, INC. NYSE-NVE

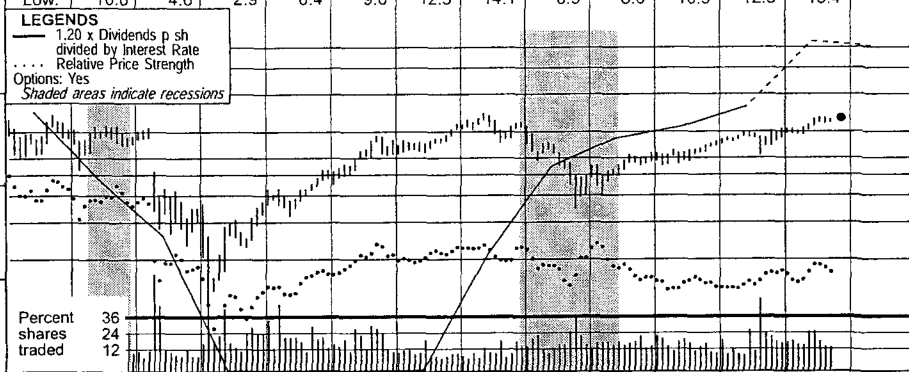
RECENT PRICE	18.56	P/E RATIO	14.7 (Trailing: 19.3; Median: 19.0)	RELATIVE P/E RATIO	0.97	DIV'D YLD	3.9%	VALUE LINE

TIMELINESS 2 Lowered 10/26/12
SAFETY 3 Raised 2/10/06
TECHNICAL 2 Raised 10/26/12
BETA .85 (1.00 = Market)

High:	17.2	16.8	7.5	10.6	15.4	17.5	19.6	17.0	12.8	14.4	16.6	19.0
Low:	10.6	4.6	2.9	6.4	9.0	12.5	14.1	6.9	8.0	10.9	12.3	15.4

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+35%)	*11%*
Low	18	(-5%)	*3%*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	1	0	0	1	0	0	0
to Sell	0	0	0	3	0	2	0	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	116	108	143
to Sell	104	115	114
Hld's(000)	202846	206533	200812

Percent shares traded 36 24 12

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.0	28.2
3 yr.	72.8	42.3
5 yr.	35.6	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.51	15.86	17.04	16.69	29.75	44.94	29.28	23.79	24.04	15.09	15.18	15.41	15.06	15.27	13.94	12.47	**12.70**	**12.90**	Revenues per sh	**13.75**
2.97	3.04	3.12	2.10	1.45	1.94	d1.27	2.75	4.65	2.42	2.89	2.91	2.02	3.45	3.48	2.91	**3.60**	**3.70**	"Cash Flow" per sh	**4.25**
1.56	1.65	1.64	.83	d.63	.34	d3.00	d1.15	.40	.44	1.14	.89	.89	.78	.96	.69	**1.25**	**1.25**	Earnings per sh A	**1.50**
1.60	1.60	1.45	1.17	1.00	.40	.20	--	--	--	--	.16	.34	.41	.45	.49	**.64**	**.74**	Div'd Decl'd per sh B ■	**1.00**
3.84	4.41	6.31	3.95	4.58	3.28	3.91	3.19	3.68	3.42	4.46	5.12	4.54	3.69	2.79	2.68	**2.10**	**2.05**	Cap'l Spending per sh	**1.50**
16.40	16.54	16.86	18.83	17.33	16.60	12.99	12.24	12.76	10.26	11.86	12.82	13.36	13.73	14.24	14.43	**15.05**	**15.55**	Book Value per sh C	**17.25**
48.79	50.40	51.27	78.43	78.48	102.11	102.18	117.24	117.47	200.79	221.03	233.74	234.32	234.83	235.32	236.00	**236.00**	**236.00**	Common Shs Outst'g D	**236.00**
13.3	12.9	15.2	25.7	--	NMF	--	--	20.9	27.5	12.6	19.1	13.3	13.9	13.2	21.7	*Bold figures are*		Avg Ann'l P/E Ratio	**15.0**
.83	.74	.79	1.46	--	NMF	--	--	1.10	1.46	.68	1.01	.80	.93	.84	1.37	*Value Line*		Relative P/E Ratio	**1.00**
7.7%	7.5%	5.8%	5.5%	6.5%	2.7%	2.2%	--	--	--	--	.9%	2.9%	3.8%	3.6%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $5138.4 mill. **Due in 5 Yrs** $1626.9 mill.
LT Debt $5130.3 mill. **LT Interest** $292.4 mill.
Incl. $51.3 mill. capitalized leases.
(LT interest earned: 2.2x)

Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/11 $811.5 mill.
Oblig. $842.1 mill.
Pfd Stock None

Common Stock 235,999,750 shs.
as of 8/1/12
MARKET CAP: $4.4 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
2991.7	2789.2	2823.8	3030.2	3356.0	3601.0	3528.1	3585.8	3280.2	2943.3	**3000**	**3050**	Revenues ($mill)	**3250**
d302.1	d129.4	75.3	86.2	238.9	197.3	208.9	182.9	227.0	163.4	**300**	**300**	Net Profit ($mill)	**365**
--	--	34.5%	33.4%	34.1%	30.7%	31.3%	29.2%	33.4%	34.7%	**33.0%**	**33.0%**	Income Tax Rate	**33.0%**
--	--	19.3%	52.2%	14.8%	29.3%	32.5%	24.3%	22.7%	12.0%	**5.0%**	**4.0%**	AFUDC % to Net Profit	**4.0%**
70.2%	70.7%	72.5%	64.4%	60.4%	58.0%	62.7%	62.2%	59.5%	59.5%	**57.5%**	**55.5%**	Long-Term Debt Ratio	**51.5%**
28.7%	28.3%	26.6%	34.8%	39.6%	42.0%	37.3%	37.8%	40.5%	40.5%	**42.5%**	**44.5%**	Common Equity Ratio	**48.5%**
4628.9	5065.1	5629.9	5927.3	6623.8	7134.4	8398.2	8527.3	8274.9	8415.0	**8310**	**8240**	Total Capital ($mill)	**8325**
4308.7	4642.7	4926.9	5397.6	6087.0	7011.0	8310.3	8665.6	8929.7	9227.1	**9315**	**9375**	Net Plant ($mill)	**9150**
NMF	.4%	4.1%	4.0%	5.8%	4.7%	4.3%	4.1%	4.8%	3.7%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
NMF	NMF	4.9%	4.1%	9.1%	6.6%	6.7%	5.7%	6.8%	4.8%	**8.5%**	**8.0%**	Return on Shr. Equity	**9.0%**
NMF	NMF	4.8%	4.0%	9.0%	6.6%	6.7%	5.7%	6.8%	4.8%	**8.5%**	**8.0%**	Return on Com Equity E	**9.0%**
NMF	NMF	4.8%	4.0%	9.0%	5.4%	4.1%	2.7%	3.6%	1.4%	**4.0%**	**3.5%**	Retained to Com Eq	**3.0%**
NMF	NMF	5%	5%	1%	18%	38%	53%	47%	71%	**51%**	**59%**	All Div'ds to Net Prof	**65%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.7	-1.4	-1.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	7140	7215	7052
Annual Load Factor (%) F	43.0	43.0	43.0
% Change Customers (yr-end)	+.1	+.3	-2.8
Fixed Charge Cov. (%)	159	181	181

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-7.5%	-5.0%	*Nil*
"Cash Flow"	6.0%	--	*4.5%*
Earnings	16.0%	4.0%	*11.0%*
Dividends	-6.0%	--	*14.0%*
Book Value	-2.0%	4.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	755.3	838.6	1219.0	772.9	3585.8
2010	714.5	782.7	1128.0	655.0	3280.2
2011	641.0	674.9	1017.8	609.6	2943.3
2012	611.4	740.7	**1050**	**597.9**	**3000**
2013	**625**	**725**	**1100**	**600**	**3050**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	d.09	.08	.78	.02	.78
2010	d.01	.16	.75	.06	.96
2011	.01	.05	.73	d.11	.69
2012	.05	.29	**.86**	**.05**	**1.25**
2013	**.06**	**.26**	**.87**	**.06**	**1.25**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.08	.08	.08	.10	.34
2009	.10	.10	.10	.11	.41
2010	.11	.11	.11	.12	.45
2011	.12	.12	.12	.13	.49
2012	.13	.17	.17		

BUSINESS: NV Energy, Inc. (formerly Sierra Pacific Resources) is a holding company formed through the 7/99 merger of Sierra Pacific (now NV Energy North) and Nevada Power (now NV Energy South). Sells electricity in west central & southern Nevada & eastern California; provides gas to Reno & Sparks, NV & environs. Customers: 1.2 mill. elec., 152,000 gas. Elec. rev. breakdown: res'l, 45%; comm'l, 25%; ind'l, 27%; other, 3%. Generating sources: gas, 49%; coal, 15%; purchased, 36%. Fuel costs: 47% of revs. '11 reported depr. rates: South, 3.0%; North, 2.9%. Has 2,800 employees. Chairman: Philip G. Satre. President & CEO: Michael W. Yackira. Inc.: NV. Address: 6226 West Sahara Ave., Las Vegas, NV 89146. Tel.: 702-402-5000. Internet: www.nvenergy.com.

We have raised our 2012 earnings estimate for NV Energy by $0.05 a share, to $1.25. That's the upper end of management's targeted range of $1.15-$1.25 a share. Due to hotter-than-normal weather, profits in the June quarter exceeded our expectation. *The company estimates* that favorable weather conditions added $0.07 a share to the bottom line in the period, compared with normal weather.

Earnings were headed up this year, anyway. The key reason is the $158.6 million rate increase that NV Energy South received at the start of 2012. Interest expense is declining, as the company has retired debt or taken advantage of low interest rates when refinancing its borrowings. Cost control has been effective, too.

We forecast flat earnings in 2013. We assume a return to normal weather patterns. Also, with the service area's economy still feeling the aftereffects of the housing crisis, NV Energy's two utilities can't count on much load growth. On the positive side, we believe that interest expense will decline again.

How will NV Energy use its free cash? With the capital budget well below the levels seen in the previous decade, and the benefits of tax-loss carryforwards, the company is generating surplus cash. Higher dividends are one way for NV Energy to use its funds. Indeed, the board of directors boosted the quarterly disbursement by $0.04 a share (30.8%) in the second quarter. (*The expectation and realization* of a hefty increase have helped lift the share price by more than 10% since the *start of 2012.*) *The company* has signaled that raises of at least 10% are achievable in the next few years. Other potential uses of surplus cash are further debt reduction and new investments.

NV Energy is building a transmission line. The company will have a 25% stake in the ON Line, which will connect northern and southern Nevada. Its stake is estimated at $138 million. The project is expected to be in service by the end of 2013.

This timely stock's yield is a bit below the utility mean. This is understandable, given the good dividend growth prospects. Strong dividend growth to 2015-2017 should produce a total return that is just slightly above the industry average.

Paul E. Debbas, CFA *November 2, 2012*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '00, 8¢; '01, 31¢; '03, (5¢); '04, (3¢); nonrec. gain (loss): '04, (21¢); '06, 20¢. '09 & '11 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'd reinstated 7/07. Div'ds historically paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '11: $6.69/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. for NV Energy North in '08: 10.6%; NV Energy South in '12: 10%; earned on avg. com. eq., '11: 4.8%. Reg. Climate: Avg. (F) NV Energy South only.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	60

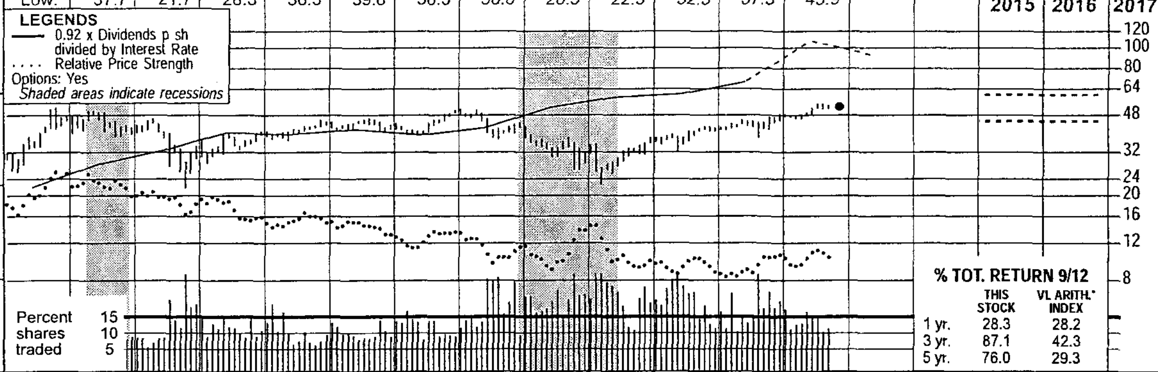
PINNACLE WEST NYSE-PNW

RECENT PRICE 52.86 | P/E RATIO 15.0 (Trailing: 15.6; Median: 14.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 2 Raised 11/11/11
SAFETY 2 Raised 5/6/11
TECHNICAL 2 Raised 11/2/12
BETA .70 (1.00 = Market)

High:	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7
Low:	37.7	21.7	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	45	(-15%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	166	152	148
to Sell	142	171	158
Hld's(000)	77718	80986	72869

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.3	28.2
3 yr.	87.1	42.3
5 yr.	76.0	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	**30.90**	**32.00**	Revenues per sh	**33.00**
5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	**7.80**	**7.95**	"Cash Flow" per sh	**8.75**
2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	**3.45**	**3.50**	Earnings per sh A	**3.75**
1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	**2.12**	**2.20**	Div'd Decl'd per sh B ■	**2.45**
2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	**8.45**	**9.60**	Cap'l Spending per sh	**8.50**
22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	**36.25**	**37.40**	Book Value per sh C	**41.50**
87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	**110.00**	**111.00**	Common Shs Outst'g D	**118.50**
11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	*Bold figures are*		Avg Ann'l P/E Ratio	**13.5**
.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	*Value Line*		Relative P/E Ratio	**.90**
3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	*estimates*		Avg Ann'l Div'd Yield	**4.8%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $3538.4 mill. **Due in 5 Yrs** $1631.7 mill.
LT Debt $3371.4 mill. **LT Interest** $193.9 mill.
Incl. $57.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $21.0 mill.
Pension Assets-12/11 $1.85 bill. **Oblig.** $2.70 bill.
Pfd Stock None

Common Stock 109,543,792 shs.
as of 7/27/12
MARKET CAP: $5.8 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
2637.3	2817.9	2899.7	2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	**3400**	**3550**	Revenues ($mill)	**3900**
215.2	230.6	235.2	223.2	317.1	298.8	213.6	229.2	330.4	328.2	**380**	**390**	Net Profit ($mill)	**455**
39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
20.5%	6.2%	6.9%	10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	**9.0%**	**12.0%**	AFUDC % to Net Profit	**9.0%**
51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	**47.5%**	**44.0%**	Long-Term Debt Ratio	**42.5%**
48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	**52.5%**	**56.0%**	Common Equity Ratio	**57.5%**
5567.9	5727.5	5535.2	6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	**7595**	**7400**	Total Capital ($mill)	**8500**
6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	**10410**	**10980**	Net Plant ($mill)	**12575**
5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	**6.5%**	**6.5%**	Return on Total Cap'l	**6.5%**
8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	**9.5%**	**9.5%**	Return on Shr. Equity	**9.0%**
8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	**9.5%**	**9.5%**	Return on Com Equity E	**9.0%**
2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	**3.5%**	**3.5%**	Retained to Com Eq	**3.5%**
64%	68%	71%	85%	63%	70%	96%	89%	66%	68%	**61%**	**62%**	All Div'ds to Net Prof	**64%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.2	-1.6	+1.8
Avg. Indust. Use (MWH)	619	619	632
Avg. Indust. Revs. per KWH (¢)	8.11	7.83	7.78
Capacity at Peak (Mw)	8635	8682	8577
Peak Load, Summer (Mw)	7218	6396	7087
Annual Load Factor (%)	49.3	50.0	50.0
% Change Customers (yr-end)	+.5	+.4	+.8
Fixed Charge Cov. (%)	248	296	308

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-3.0%	-1.0%	1.0%
"Cash Flow"	-1.0%	--	2.5%
Earnings	-2.0%	1.0%	5.0%
Dividends	4.0%	1.5%	2.5%
Book Value	2.0%	--	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	625.9	836.0	1142.2	693.0	3297.1
2010	620.3	820.6	1139.1	683.6	3263.6
2011	648.9	799.8	1124.8	667.9	3241.4
2012	620.6	878.6	**1200**	**700.8**	**3400**
2013	**650**	**875**	**1300**	**725**	**3550**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	d.36	.74	2.07	d.19	2.26
2010	.07	.83	2.08	.06	3.08
2011	d.15	.78	2.24	.11	2.99
2012	d.07	1.12	**2.30**	**.10**	**3.45**
2013	**Nil**	**1.05**	**2.35**	**.10**	**3.50**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.525	.525	.525	.525	2.10
2009	.525	.525	.525	.525	2.10
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525	.545	

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 47%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 37%; nuclear, 27%; gas, 17%; purchased, 19%. Fuel costs: 31% of revenues. Has 6,700 employees. '11 reported deprec. rate: 3.0%. Chairman, President & CEO: Donald E. Brandt. Inc.: Arizona. Address: 400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's board of directors has raised the dividend. The board raised the quarterly disbursement by $0.02 a share (3.8%). This was the first hike in the payout since the fourth quarter of 2006. Pinnacle hasn't stated what its dividend policy will be.

We have raised our 2012 earnings estimate by $0.25 a share, to $3.45. June-quarter profits were well above our expectation thanks to weather patterns that were even hotter than usual. Regardless of the weather, earnings were probably headed higher this year, anyway, thanks to a $116.3 million (4%) rate increase that took effect in mid-2012. Our revised estimate is within Pinnacle's targeted range of $3.35-$3.50 a share.

An asset acquisition is pending. Pinnacle's utility subsidiary, Arizona Public Service, has agreed to pay $294 million for another utility's 739-megawatt stake in units 4 and 5 of the Four Corners coal-fired generating station. APS would have to spend about $300 million for environmental upgrades to units 4 and 5, but would avoid $600 million of improvements that would have been necessary to keep units 1, 2, and 3 *running*. (The older units will be shut down.) The utility plans to issue long-term debt to finance the purchase. It will likely receive rate relief in mid-2013 to place Four Corners 4 and 5 in the rate base. Note that our 2013 earnings estimate will not reflect the asset purchase until after the deal has been completed.

Base rates are frozen until mid-2016, but the utility will obtain revenues through some regulatory mechanisms before that time. In addition to any increase for Four Corners 4 and 5, APS should benefit from annual rate hikes for transmission investment; rate surcharges for renewable investment (such as its AZ Sun solar program); and partial compensation for the decline in customer usage that results from conservation programs. This should enable earnings to increase in 2014 and 2015.

This timely stock has a yield that is average for a utility, even after the dividend hike this quarter. With the share price near the midpoint of our 3- to 5-year Target Price Range, however, total return potential *is unimpressive.*

Paul E. Debbas, CFA *November 2, 2012*

(A) Diluted egs. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. *gains (losses) from disc. ops.:* '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (1¢). '10 EPS don't add due to change in shares, '11 due to *rounding. Next earnings report due early Feb.* (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '11: $14.32/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '11: 8.8%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	65

PNM RESOURCES NYSE-PNM

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
21.76	16.4 (Trailing: 16.4 / Median: 16.0)	1.08	2.7%

VALUE LINE

TIMELINESS 3 Lowered 8/31/12
SAFETY 3 Lowered 5/9/08
TECHNICAL 2 Raised 10/26/12
BETA .95 (1.00 = Market)

High:	25.2	20.5	19.6	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.2
Low:	15.3	11.5	12.6	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3

Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

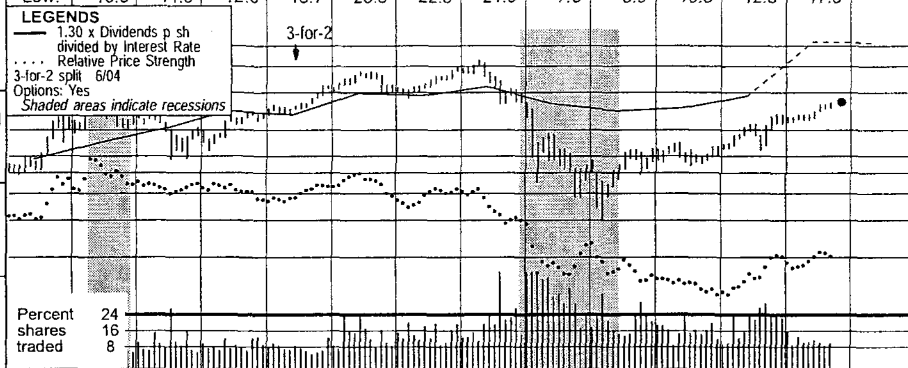
	Price	Gain	Ann'l Total Return
High	30	(+40%)	11%
Low	20	(-10%)	2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	3	0	1	0	0	1
to Sell	0	0	0	4	0	1	0	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	63	84	76
to Sell	113	86	91
Hld's(000)	69828	69113	69724



% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.7	28.2
3 yr.	100.6	42.3
5 yr.	11.3	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
14.10	18.12	17.43	18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	**16.65**	**17.20**	Revenues per sh	**22.35**
2.61	2.58	3.04	2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	**3.20**	**3.30**	"Cash Flow" per sh	**3.80**
1.15	1.25	1.50	1.29	1.55	2.61	1.07	1.15	1.43	1.59	1.72	.76	.11	.58	.87	1.08	**1.30**	**1.40**	Earnings per sh A	**2.05**
.24	.42	.51	.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	**.58**	**.70**	Div'd Decl'd per sh B ■†	**1.00**
1.42	2.05	2.06	1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	**3.60**	**3.15**	Cap'l Spending per sh	**2.60**
12.04	12.84	13.75	14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	**20.15**	**20.90**	Book Value per sh C	**22.40**
62.66	62.66	62.66	61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	**80.00**	**80.00**	Common Shs Outst'g D	**85.00**
11.0	10.0	9.8	9.5	8.5	7.3	15.1	14.7	15.0	17.1	15.6	NMF	NMF	18.1	14.0	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	**12.0**
.69	.58	.51	.54	.55	.37	.82	.84	.79	.91	.84	NMF	NMF	1.21	.89	.91	*Value Line*		Relative P/E Ratio	**.80**
1.9%	3.3%	3.5%	4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	*estimates*		Avg Ann'l Div'd Yield	**4.1%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1881.3 mill. **Due in 5 Yrs** $236.8 mill.
LT Debt $1672.0 mill. **LT Interest** $100 mill.
(LT interest earned: 2.8x)
Pension Assets-12/11 $427.4 mill. **Oblig.** $588.9 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
As of 7/27/12
MARKET CAP: $1.7 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1169.0	1455.7	1604.8	2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	**1330**	**1375**	Revenues ($mill)	**1900**
64.3	68.9	88.3	106.6	122.1	59.9	8.1	53.5	80.0	96.6	**100**	**115**	Net Profit ($mill)	**175**
24.5%	29.0%	28.2%	31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	**40.0%**	**40.0%**	Income Tax Rate	**40.0%**
13.0%	NMF	5.6%	15.6%	4.2%	NMF	NMF	6.4%	7.1%	8.8%	**7.5%**	**7.5%**	AFUDC % to Net Profit	**8.0%**
49.8%	47.5%	47.1%	57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	**51.5%**	**51.0%**	Long-Term Debt Ratio	**50.5%**
49.5%	51.9%	52.4%	42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	**48.5%**	**48.5%**	Common Equity Ratio	**49.0%**
1966.9	2077.3	2098.9	3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	**3345**	**3455**	Total Capital ($mill)	**3900**
1867.3	2194.4	2324.6	2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	**3810**	**4000**	Net Plant ($mill)	**4630**
4.7%	4.7%	5.3%	4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	**5.0%**	**5.0%**	Return on Total Cap'l	**6.0%**
6.5%	6.3%	7.9%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	**6.0%**	**7.0%**	Return on Shr. Equity	**9.0%**
6.5%	6.3%	8.0%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	**6.0%**	**7.0%**	Return on Com Equity E	**9.0%**
3.1%	3.0%	4.5%	4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	**3.5%**	**3.5%**	Retained to Com Eq	**4.5%**
53%	53%	44%	48%	49%	117%	NMF	86%	58%	47%	**47%**	**49%**	All Div'ds to Net Prof	**50%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.2	-5.7	+2.5
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2711	2631	2547
Peak Load, Summer (Mw)	1866	1973	1938
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	-.9	-.7	--
Fixed Charge Cov. (%)	156	182	201

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-3.5%	-7.5%	2.0%
"Cash Flow"	-2.5%	-4.5%	5.5%
Earnings	-7.5%	-12.0%	16.0%
Dividends	-.5%	-8.0%	12.0%
Book Value	1.5%	-1.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	385.9	401.1	477.7	383.0	1647.7
2010	383.5	405.8	503.7	380.5	1673.5
2011	387.7	415.5	549.5	347.9	1700.6
2012	305.4	323.9	**400**	**300.7**	**1330**
2013	**310**	**335**	**425**	**305**	**1375**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.15	.01	.60	d.18	.58
2010	.06	.21	.63	d.03	.87
2011	.04	.20	.61	.22	1.08
2012	.17	.33	**.60**	**.20**	**1.30**
2013	**.20**	**.35**	**.65**	**.20**	**1.40**

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.23	.125	.125	.71
2009	.125	.125	.125	.125	.50
2010	.125	.125	.125	.125	.50
2011	.125	.125	.125	.125	.50
2012	.145	.145	.145		

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP) which engage in the generation, transmission, and distribution of electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '11: residential, 38%; commercial, 36%; industrial, 8%; other, 18%. Fuels: coal, 62%; nuclear, 30%; gas/oil, 8%. Fuel costs: 54% of revs. '11 dep. rate: 3.0%. Has 1,951 employees. Chrmn., Pres. & CEO: Patricia K. Collawn. Inc.: NM. Addr.: Alvarado Square, Albuquerque, NM. 87158. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources posted solid results during the second quarter. Ongoing earnings increased both sequentially, as well as compared to the year-earlier figure, to $0.33 a share. PNM continued to benefit from higher retail rates. Warmer temperatures in June and lower outage costs helped, as well. Going forward, we expect this rate relief to positively influence the bottom line for the remainder of the year. Thus, we have increased our estimate for 2012 by a nickel, to $1.30 a share. *(Note: Earnings were scheduled to be released as we rolled the presses on this Issue.)*

The electric utility remains active on the regulatory front. The company is waiting for the Federal Energy Regulatory Commission's (FERC) final approval regarding its transmission case (filed July 3rd). For this black-box settlement, an increased revenue number has been approved, but the FERC has yet to specify a return-on-equity figure. Indeed, the timing of the settlement has not been announced. As a result, we have boosted our top-line projections for 2012 and 2013, to $1.33 billion and $1.38 billion, respectively. What's more, the company has taken numerous steps to finalize its renewable energy rider, 2013 renewable energy plan, and FERC generation case.

The Environmental Protection Agency (EPA) extended its 90-day stay. The EPA granted PNM an additional 45 days to propose its alternative to selective catalytic reduction (SCR) technology, which is expected to cost more than $750 million to install. This plan involves converting two coal-fired plants at its San Juan Generating Station (SJGS) to natural gas or other noncoal generation by 2017. The remaining two units would have selective noncatalytic reduction technology installed; a less expensive alternative. That said, this extension will expire on November 29th, and PNM is still expected to remain on track to meet the 2016 deadline.

This stock is an unattractive selection for income-oriented investors. The company's 2.7% dividend yield is well below the utility industry average of 4.1%. Additionally, the issue dropped a notch in Timeliness, to 3 (Average).

Michelle Jensen *November 2, 2012*

(A) EPS diluted. Excl. nonrecur. gains (losses): '97, 3¢; '98, net (16¢); '99, 5¢; '00, 14¢; '01, (10¢); '03, 45¢; '05, (56¢); '07, 14¢; '08, ($3.77); '10, ($1.36). Egs. may not sum due to rounding. Next egs. report due mid-Feb. (B) Div'ds hist. paid in mid Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '11: $3.21/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '08: 10.1%; earned on avg. com. eq., '11: 6.1%. Regulatory Climate: Avg.

Company's Financial Strength	B
Stock's Price Stability	65
Price Growth Persistence	25
Earnings Predictability	15

PORTLAND GENERAL NYSE-POR

RECENT PRICE 27.44 | P/E RATIO 14.2 (Trailing: 15.9; Median: NMF) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Lowered 8/19/11

SAFETY 2 Raised 5/4/12

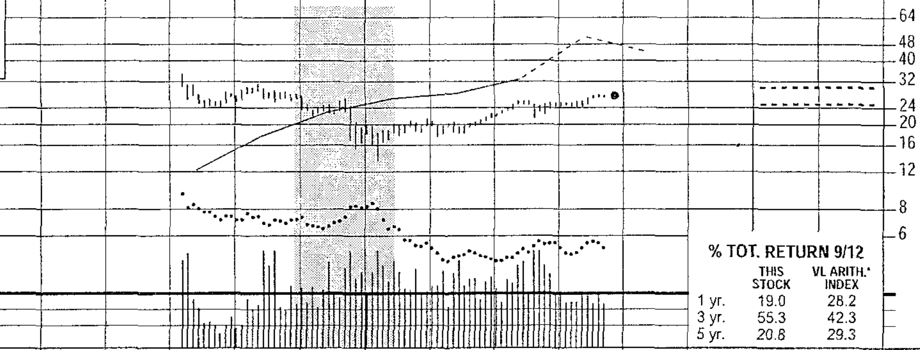
TECHNICAL 3 Lowered 9/14/12

BETA .75 (1.00 = Market)

LEGENDS
— 0.87 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions

	2006	2007	2008	2009	2010	2011	2012
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+10%)	7%
Low	25	(-10%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	100	124	116
to Sell	122	105	109
Hld's(000)	67569	67722	68793

Percent shares traded 15 10 5

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.0	28.2
3 yr.	55.3	42.3
5 yr.	20.8	29.3

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2002	2003	2004	2005[G]	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	**24.15**	**24.75**	Revenues per sh	**27.50**
--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	**5.05**	**5.30**	"Cash Flow" per sh	**6.25**
--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	**1.90**	**1.95**	Earnings per sh A	**2.25**
--	--	--	--	.68	.93	.97	1.01	1.04	1.06	**1.08**	**1.11**	Div'd Decl'd per sh B ■ †	**1.25**
--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	**4.40**	**4.05**	Cap'l Spending per sh	**4.75**
--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	**22.80**	**23.60**	Book Value per sh C	**26.00**
--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	**75.55**	**75.75**	Common Shs Outst'g D	**76.50**
--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	*Bold figures are*		Avg Ann'l P/E Ratio	**12.5**
--	--	--	--	1.26	.63	.98	.96	.76	.78	*Value Line*		Relative P/E Ratio	**.85**
--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	*estimates*		Avg Ann'l Div'd Yield	**4.6%**
--	--	1454.0	1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	**1825**	**1875**	Revenues ($mill)	**2100**
--	--	92.0	64.0	71.0	145.0	87.0	95.0	125.0	147.0	**140**	**145**	Net Profit ($mill)	**175**
--	--	37.0%	40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	**30.0%**	**30.0%**	Income Tax Rate	**30.0%**
--	--	9.8%	18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	**6.0%**	**5.0%**	AFUDC % to Net Profit	**3.0%**
--	--	41.1%	42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	**47.0%**	**48.0%**	Long-Term Debt Ratio	**46.0%**
--	--	58.9%	57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	**53.0%**	**52.0%**	Common Equity Ratio	**54.0%**
--	--	2171.0	2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	**3260**	**3420**	Total Capital ($mill)	**3700**
--	--	2275.0	2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	**4380**	**4430**	Net Plant ($mill)	**4500**
--	--	5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	**8.0%**	**8.0%**	Return on Shr. Equity	**9.0%**
--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	**8.0%**	**8.0%**	Return on Com Equity E	**9.0%**
--	--	7.2%	5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	**3.5%**	**3.5%**	Retained to Com Eq	**4.0%**
--	--	--	--	39%	40%	69%	76%	62%	54%	**57%**	**57%**	All Div'ds to Net Prof	**54%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1736.0 mill. **Due in 5 Yrs** $337.0 mill.
LT Debt $1586.0 mill. **LT Interest** $91.0 mill.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $9.0 mill.

Pension Assets-12/11 $487.0 mill. **Oblig.** $634.0 mill.

Pfd Stock None

Common Stock 75,527,955 shs. as of 7/27/12

MARKET CAP: $2.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.3	-3.1	+3.3
Avg. Indust. Use (MWH)	9343	12986	14932
Avg. Indust. Revs. per KWH (¢)	7.07	6.62	6.16
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	3949	3582	3555
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.5	+.2
Fixed Charge Cov. (%)	179	224	273

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	--	2.5%
"Cash Flow"	--	-.5%	5.0%
Earnings	--	8.5%	5.5%
Dividends	--	NMF	3.5%
Book Value	--	2.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	485.0	389.0	445.0	485.0	1804.0
2010	449.0	415.0	464.0	455.0	1783.0
2011	484.0	411.0	439.0	479.0	1813.0
2012	479.0	413.0	**453**	**480**	**1825**
2013	**495**	**415**	**470**	**495**	**1875**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.47	.31	.43	.11	1.31
2010	.36	.32	.65	.34	1.66
2011	.92	.29	.36	.38	1.95
2012	.65	.34	**.50**	**.41**	**1.90**
2013	**.68**	**.37**	**.50**	**.40**	**1.95**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.235	.245	.245	.245	.97
2009	.245	.245	.255	.255	1.00
2010	.255	.255	.26	.26	1.03
2011	.26	.26	.265	.265	1.05
2012	.265	.265	.27	.27	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 828,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 35%; industrial, 12%; other, 5%. Generating sources: coal, 19%; gas, 10%; hydro, 9%; wind, 6%; purchased, 56%. Fuel costs: 42% of revenues. '11 reported depreciation rate: 3.7%. Has 2,600 employees. Chairman: Corbin A. McNeill, Jr. Chief Executive Officer and President: Jim Piro. Incorporated: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric is awaiting the outcome of three requests for proposals (RFPs). These RFPs are for the utility's needs for base-load energy, peaking capacity, and renewable generating capacity in the next several years. PGE has bid into each RFP, which will be evaluated independently. Whether the company builds projects or purchases power will heavily influence its capital spending and financing plans — as well as its earning power — through 2017. If PGE's bid is selected in each case, this would necessitate capital spending projected at $1.5 billion-$1.9 billion from 2013 through 2017. The final decisions are likely to be submitted to the Public Utility Commission of Oregon in the first quarter of 2013 (or perhaps in late 2012).

We do not assume in our estimates and projections that PGE wins any RFPs. This is not a likely outcome, but it is impossible to make any assumptions about what the utility will build. Accordingly, our estimates and projections beginning in 2013 might well be conservative. (The company would record noncash credits to income for Allowance for Funds Used During Construction while the projects are being built.) Note that the result of the RFPs will also have an influence on whether PGE files a general rate case next year, and if so, what the timing will be.

Separately, PGE wants to build a transmission line. The company would likely spend $750 million-$800 million, depending upon whether another utility in the region takes a 25% stake in the project. Numerous negotiations and permitting processes are under way. If all necessary approvals are obtained, construction would begin in 2014, and the line would be operational in late 2016 or early 2017.

We expect earnings to decline slightly in 2012. The first-quarter comparison was difficult, thanks to the favorable weather and hydro conditions that boosted the bottom line in early 2011. Our profit estimate is within PGE's targeted range of $1.85-$2.00 a share.

This stock does not stand out among utility issues. The dividend yield and 3- to 5-year total return potential are only about average for this industry.

Paul E. Debbas, CFA *November 2, 2012*

(A) Diluted EPS. '09 & '10 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $7.88/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq., '11: 9.0%. Regulatory Climate: Below Average. (F) Summer peak in '09. (G) '05 per-share data are pro forma, based on shares outstanding when the stock began trading in '06.

mon equity in '11: 10.0%; earned on average

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	45

SOUTHERN CO. NYSE-SO

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
42.95	15.5	(Trailing: 16.9 / Median: 15.0)	1.07	4.7%

VALUE LINE

TIMELINESS 2 Raised 8/24/12

SAFETY 1 Raised 6/3/05

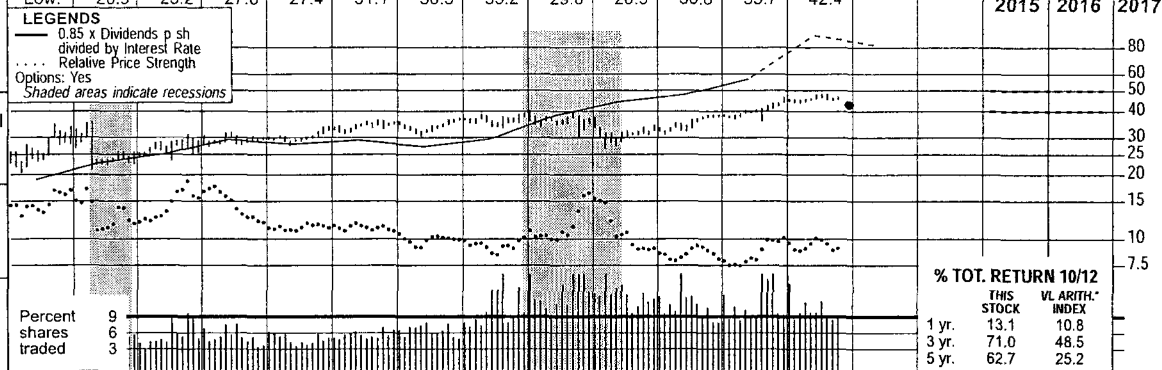
TECHNICAL 3 Lowered 11/23/12

BETA .55 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	35.7	31.1	32.0	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	48.6		
Low:	20.9	23.2	27.0	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	42.4		

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 0.85 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	8%
Low	40	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	0	0	1	0	0	0
Options	0	1	0	1	2	3	2	2	1
to Sell	0	1	0	1	2	3	2	2	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	435	385	432
to Sell	307	387	331
Hld's(000)	374903	372243	338977

Percent shares traded 9 6 3

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	10.8
3 yr.	71.0	48.5
5 yr.	62.7	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.30	18.19	16.34	17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.10	19.55	Revenues per sh	21.75
3.64	3.86	4.26	4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.15	5.45	"Cash Flow" per sh	6.25
1.68	1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.65	2.80	Earnings per sh A	3.25
1.26	1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.02	Div'd Decl'd per sh B ■ †	2.25
1.82	2.68	2.87	3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	6.25	5.65	Cap'l Spending per sh	6.75
13.61	13.91	14.04	13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	20.95	21.70	Book Value per sh C	25.75
677.04	693.42	697.75	665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	868.00	870.00	Common Shs Outst'g D	915.00
13.8	14.0	15.7	14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	Bold figures are		Avg Ann'l P/E Ratio	14.0
.86	.81	.82	.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	1.00	Value Line		Relative P/E Ratio	.95
5.5%	5.9%	4.9%	5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	estimates		Avg Ann'l Div'd Yield	5.0%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $21987 mill. **Due in 5 Yrs** $7119.0 mill.
LT Debt $19459 mill. **LT Interest** $856.0 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $121.0 mill.
Pension Assets-12/11 $6.80 bill. **Oblig.** $8.08 bill.
Pfd Stock $1082 mill. **Pfd Div'd** $65.0 mill.
Incl. 1 mill. shs. 4.20%-5.44% cum. pfd. ($100 par); 12 mill. shs. 4.95%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 3 mill. shs. 6.0%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 874,796,883 shs.
MARKET CAP: $38 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
10549	11251	11902	13554	14356	15353	17127	15743	17456	17657	16600	17000	Revenues ($mill)	20000
1510.0	1602.1	1589.0	1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	2365	2510	Net Profit ($mill)	3040
25.9%	27.0%	27.0%	26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	32.0%	32.0%	Income Tax Rate	32.0%
5.4%	4.6%	5.2%	4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	13.0%	13.0%	AFUDC % to Net Profit	13.0%
43.1%	45.9%	53.5%	53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	52.0%	52.0%	Long-Term Debt Ratio	53.0%
43.4%	43.6%	44.1%	44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	45.5%	45.5%	Common Equity Ratio	45.0%
20086	22135	23288	24131	24618	27608	31174	34091	35438	37307	40025	41725	Total Capital ($mill)	52200
24642	27534	28361	29480	31092	33327	35878	39230	42002	45010	48275	50900	Net Plant ($mill)	61500
8.6%	8.4%	8.1%	8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	7.0%	7.0%	Return on Total Cap'l	7.0%
13.2%	13.4%	14.7%	14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	12.5%	12.5%	Return on Shr. Equity	12.5%
15.1%	14.8%	14.9%	14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	12.5%	13.0%	Return on Com Equity E	12.5%
4.1%	4.4%	4.7%	4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	3.5%	3.5%	Retained to Com Eq	4.0%
76%	73%	69%	70%	73%	70%	74%	75%	77%	73%	74%	72%	All Div'ds to Net Prof	69%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.8	+7.6	-2.7
Avg. Indust. Use (MWH)	3095	3332	3438
Avg. Indust. Revs. per KWH (¢)	6.04	6.20	6.37
Capacity at Yearend (Mw)	42932	42963	43555
Peak Load, Summer (Mw)	34471	36321	36956
Annual Load Factor (%)	60.6	62.2	59.0
% Change Customers (yr-end)	--	+.3	-.1
Fixed Charge Cov. (%)	310	342	397

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	2.5%	1.5%
"Cash Flow"	2.0%	3.5%	5.0%
Earnings	3.0%	3.0%	5.0%
Dividends	3.0%	4.0%	4.0%
Book Value	3.5%	6.0%	5.0%

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3666	3885	4682	3510	15743
2010	4157	4208	5320	3771	17456
2011	4012	4521	5428	3696	17657
2012	3604	4181	5049	3766	16600
2013	3800	4200	5200	3800	17000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.41	.61	.99	.31	2.32
2010	.60	.62	.98	.18	2.36
2011	.49	.70	1.06	.30	2.55
2012	.42	.71	1.11	.41	2.65
2013	.50	.75	1.20	.35	2.80

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.4025	.42	.42	.42	1.66
2009	.42	.4375	.4375	.4375	1.73
2010	.4375	.455	.455	.455	1.80
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49	.49		

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 35%; commercial, 30%; industrial, 19%; wholesale, 11%; other, 5%. Retail revenues by state: Georgia, 51%; Alabama, 33%; Florida, 9%; Mississippi, 7%. Generating sources: coal, 49%; oil & gas, 28%; nuclear, 15%; hydro, 2%; purchased, 6%. Fuel costs: 39% of revenues. '11 reported deprec. rate (utility): 3.2%. Has 26,400 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

Southern Company's largest utility subsidiary, Georgia Power, is building two nuclear units. Georgia Power will have a 45.7% stake (about 1,000 megawatts) in Vogtle 3 and 4, which are scheduled to begin commercial operation in 2016 and 2017. The projected cost is $6.2 billion, which would comply with the cost estimate that has been certified by the Georgia Public Service Commission, but $425 million of costs are in dispute between the utility and its contractors. At least low financing costs have helped keep the project on budget.

Mississippi Power also has a large project under construction. The utility is building a 582-mw coal gasification plant at a projected cost of $2.88 billion. It is expected to begin commercial operation in May of 2014.

Earnings should improve in 2012 and 2013. At the start of this year, Georgia Power received the second of three annual rate hikes. The utility will get the final increase at the beginning of 2013. Southern Company's utilities in other jurisdictions have received rate relief this year, too. We have fine-tuned our 2012 share-net estimate up a nickel, to $2.65. This remains within the company's targeted range of $2.58-$2.70. For now, we're sticking with our 2013 profit forecast of $2.80 a share, but we are concerned about signs of a slowdown in the service area's economy.

A rate application is upcoming. In mid-2013, Georgia Power will file a general rate case for an order that will take effect at the start of 2014. Although there is regulatory risk whenever a utility puts forth a rate case, we note that Southern Company's utilities have typically done an effective job of managing the regulatory process.

Finances are solid. The fixed-charge coverage is well above the industry average. The common-equity ratio is in good shape, and returns on equity are healthy. Southern Company merits a Financial Strength rating of A, and its stock is ranked 1 (Highest) for Safety.

Timely Southern Company stock has a dividend yield that is slightly above the utility average. Total return potential to 2015-2017 is a cut below the industry average, however.

Paul E. Debbas, CFA *November 23, 2012*

(A) Diluted earnings. Excl. nonrecurring gain (loss): '03, 6¢; '09, (25¢). '10 EPS don't add due to change in shares. Next earnings report due late Jan. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $6.27/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 12.5%. Earned on avg. com. eq., '11: 13.0%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

WESTAR ENERGY NYSE-WR

RECENT PRICE 29.31 | P/E RATIO 14.7 (Trailing: 16.0 Median: 14.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 2 Raised 8/24/12
SAFETY 2 Raised 4/1/05
TECHNICAL 3 Raised 8/10/12
BETA .75 (1.00 = Market)

High:	25.9	18.0	20.5	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0
Low:	15.6	8.5	9.8	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

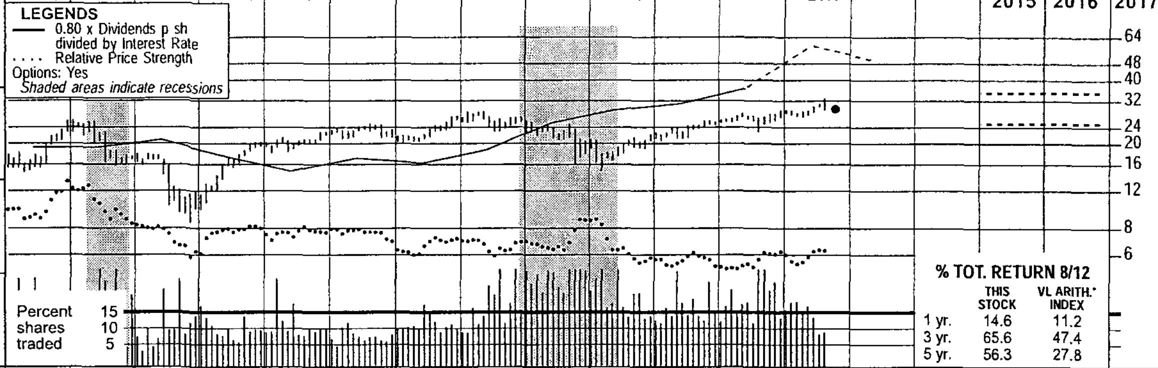
	Price	Gain	Ann'l Total Return
High	35	(+20%)	9%
Low	25	(-15%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	1	0	1	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	118	129	126
to Sell	83	93	103
Hld's(000)	69839	69508	69803



% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.6	11.2
3 yr.	65.6	47.4
5 yr.	56.3	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.67	32.90	30.86	30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	**17.70**	**18.30**	Revenues per sh	**20.15**
5.52	3.47	6.35	7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	**4.20**	**4.40**	"Cash Flow" per sh	**5.05**
2.60	d.46	2.13	1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	**1.95**	**2.05**	Earnings per sh A	**2.40**
2.07	2.10	2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	**1.32**	**1.36**	Div'd Decl'd per sh B■†	**1.48**
3.09	3.22	2.77	4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	**6.70**	**7.05**	Cap'l Spending per sh	**7.85**
25.14	30.79	29.40	27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.20	**23.60**	**25.40**	Book Value per sh C	**28.35**
64.63	65.41	65.91	67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	**127.00**	**128.00**	Common Shs Outst'g E	**134.00**
11.7	--	18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**12.5**
.73	--	.96	.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.94			Relative P/E Ratio	**.85**
6.8%	6.3%	5.5%	8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%			Avg Ann'l Div'd Yield	**4.9%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $3436.7 mill. Due in 5 Yrs $753.9 mill.
LT Debt $3042.5 mill. LT Interest $160.0 mill.
(LT interest earned: 3.1x)

Pension Assets-12/11 $481 mill. Oblig. $876 mill.

Pfd Stock None

Common Stock 126,315,391 shs.
as of 7/31/12
MARKET CAP: $3.7 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1771.1	1461.1	1464.5	1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	**2250**	**2340**	Revenues ($mill)	**2700**
72.0	108.1	100.1	134.9	165.3	168.4	136.8	141.3	203.9	214.0	**250**	**265**	Net Profit ($mill)	**325**
53.4%	43.1%	25.0%	31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	30.4%	**30.0%**	**30.0%**	Income Tax Rate	**30.0%**
--	5.0%	--	--	--	10.4%	--	--	10.4%	10.0%	**10.0%**	**10.0%**	AFUDC % to Net Profit	**10.0%**
71.6%	66.2%	53.8%	52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	**49.0%**	**49.5%**	Long-Term Debt Ratio	**50.0%**
22.9%	33.2%	45.5%	47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.0%	**51.0%**	**50.5%**	Common Equity Ratio	**50.0%**
4272.4	3127.3	3049.2	3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	**5900**	**6450**	Total Capital ($mill)	**7600**
3995.4	3909.5	3911.0	3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	**7200**	**7500**	Net Plant ($mill)	**8500**
4.4%	7.0%	5.5%	6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.2%	**5.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
5.9%	10.2%	7.1%	9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.6%	**8.5%**	**8.0%**	Return on Shr. Equity	**8.5%**
7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	**8.5%**	**8.0%**	Return on Com Equity D	**8.5%**
NMF	4.9%	3.2%	4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.2%	**2.5%**	**3.0%**	Retained to Com Eq	**3.5%**
120%	53%	56%	55%	49%	53%	80%	87%	63%	72%	**67%**	**66%**	All Div'ds to Net Prof	**60%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.0	+6.2	+1.0
Avg. Indust. Use (MWH)	5145	5468	5589
Avg. Indust. Revs. per KWH (¢)	5.67	5.82	6.22
Capacity at Peak (Mw)	6807	6756	6784
Peak Load, Summer (Mw)	4545	5485	5549
Annual Load Factor (%)	54.5	55.0	55.5
% Change Customers (yr-end)	+.9	+.3	+.1
Fixed Charge Cov. (%)	226	267	297

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-6.0%	-1.0%	2.5%
"Cash Flow"	-6.0%	1.5%	4.5%
Earnings	--	1.0%	6.5%
Dividends	-4.5%	7.0%	3.0%
Book Value	-3.0%	6.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	421.8	467.8	528.5	440.1	1858.2
2010	459.8	495.2	644.4	456.8	2056.2
2011	481.7	524.9	678.2	486.2	2171.0
2012	475.7	566.3	**690**	**518**	**2250**
2013	**520**	**575**	**710**	**535**	**2340**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.10	.35	.73	.10	1.28
2010	.27	.47	1.01	.05	1.80
2011	.27	.38	.98	.16	1.79
2012	.21	.48	**1.02**	**.24**	**1.95**
2013	**.25**	**.46**	**1.08**	**.26**	**2.05**

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.27	.29	.29	.29	1.14
2009	.29	.30	.30	.30	1.19
2010	.30	.31	.31	.31	1.23
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 688,000 customers in Kansas. Electric revenue sources: residential and rural, 42%; commercial, 37%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2011 depreciation rate: 4.2%. Estimated plant age: 14 years. Fuels: coal, 51%; nuclear, 8%; gas, 41%. Has 2,424 employees. BlackRock, Inc. owns 5.9% of common; off. & dir., less than 1% (3/12 proxy). Chairman: Charles Q. Chandler IV. Chief Executive Officer and President: Mark A. Ruelle. Inc.: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy reported strong results for the second quarter. The top line advanced at a moderate clip. The company benefited from healthy demand resulting from warmer weather during the period. Solid growth from the Retail businesses and an impressive advance in Transmission revenue more than offset a decline in Wholesale revenue. Healthy top-line results were partly offset by greater operating costs, however. Even so, share net of $0.48 compared favorably with the prior-year tally.

Favorable comparisons ought to continue in the coming quarters. A rate increase of $50 million was approved and implemented earlier in the year. This ought give retail sales a boost. Healthy growth should continue in the Transmission business, though weakness may well persist in the Wholesale line. Overall, we expect higher revenues and share earnings for the company for full-year 2012. Growth ought to continue in 2013.

Investment in operations ought to pay off going forward. All of the company's large projects remain on schedule and within budget. Westar has finished an upgrade of air quality equipment at its Lawrence Energy Center, and an additional improvement is slated for completion by the end of the year. Major environmental projects at the Jeffrey and LaCygne energy centers are also progressing well. The Prairie Wind joint venture is also coming along nicely. Westar has acquired the majority of the rights of way, and has begun clearing. The project is expected to be completed in late 2014.

This stock is favorably ranked for year-ahead performance. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. Moreover, Westar earns good marks for Safety, Price Stability, and Earnings Predictability. In addition, the stock has below-average volatility (Beta: 0.75). Overall, Westar has unimpressive, but fairly well-defined, total return potential for the pull to 2015-2017. Conservative, income-seeking investors may find this issue attractive, considering the healthy dividend yield. Subscribers looking for strong capital appreciation can probably find better choices elsewhere.

Michael Napoli, CFA *September 21, 2012*

(A) EPS diluted from 2010 onward. Excl. nonrecur gains (losses): '96, ($0.19); '97, $7.97; '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Next egs. rep't due in November. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2011: $8.32/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '12: 10.0%; earned on avg. com. eq., '11: 8.2%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	80

ATTACHMENT B

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AMERICAN ELEC PWR INC (NYSE)

ZACKS RANK: 3 - HOLD

AEP 41.29 ▼-0.23 (-0.55%) Vol. 1,451,965 14:35 ET

American Electric Power is a public utility holding company which owns,directly or indirectly, all of the outstanding common stock of its domesticelectric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. The Company's operations are divided into three business segments: Wholesale, Energy Delivery and Other.

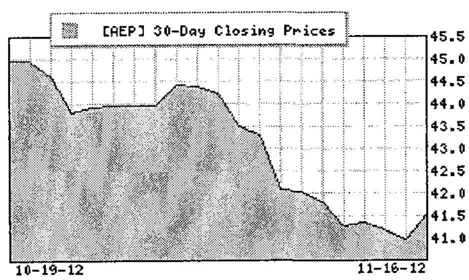
General Information

AMER ELEC PWR
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215
Phone: 614-716-1000
Fax: 614-716-1823
Web: http://www.aep.com
Email: klkozero@aep.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	01/25/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	41.52
52 Week High	45.41
52 Week Low	36.97
Beta	0.47
20 Day Moving Average	2,736,342.00
Target Price Consensus	46



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.69	4 Week	-2.72
12 Week	-2.99	12 Week	0.67
YTD	0.51	YTD	-7.05

Share Information		Dividend Information	
Shares Outstanding (millions)	484.90	Dividend Yield	4.53%
		Annual Dividend	$1.88
Market Capitalization (millions)	20,133.17	Payout Ratio	0.63
Short Ratio	3.25	Change in Payout Ratio	0.07
Last Split Date	N/A	Last Dividend Payout / Amount	11/07/2012 / $0.47

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.45	Current (1=Strong Buy, 5=Strong Sell)	2.03
Current Year EPS Consensus Estimate	3.05	30 Days Ago	2.03
Estimated Long-Term EPS Growth Rate	3.50	60 Days Ago	2.03
Next EPS Report Date	01/25/2013	90 Days Ago	2.03

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
~~Current FY Estimate:~~	~~13.63~~	~~vs. Previous Year~~	~~-12.82%~~	~~vs. Previous Year~~	~~-3.35%~~
Trailing 12 Months:	13.89	vs. Previous Quarter	32.47%	vs. Previous Quarter:	17.04%
PEG Ratio	3.91				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.32	09/30/12	9.69	09/30/12	2.73

Price/Cash Flow	6.08	06/30/12	10.27	06/30/12	2.90
Price / Sales	1.36	03/31/12	10.33	03/31/12	2.90
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	0.68	09/30/12	0.47	09/30/12	9.81
06/30/12	0.70	06/30/12	0.47	06/30/12	10.18
03/31/12	0.66	03/31/12	0.44	03/31/12	10.03
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	13.96	09/30/12	13.96	09/30/12	31.57
06/30/12	15.63	06/30/12	15.63	06/30/12	30.99
03/31/12	15.43	03/31/12	15.43	03/31/12	30.70
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	6.61	09/30/12	0.98	09/30/12	49.42
06/30/12	7.09	06/30/12	1.02	06/30/12	50.51
03/31/12	7.45	03/31/12	1.03	03/31/12	50.80

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CLECO CORP NEW (NYSE)

ZACKS RANK: 2 - BUY

CNL 39.41 0.15 (0.38%) Vol. 262,984 14:35 ET

Cleco Corp. is an energy services company based in central Louisiana. Their two primary businesses are Cleco Power LLC, a regulated electric utility business, and Cleco Midstream Resources LLC, a wholesale energy business. They use a mixture of western coal, petroleum coke (petcoke), lignite, oil, and natural gas to serve their customers. This diverse fuel mix helps Cleco deliver reliable, low-cost power to its customers.

General Information

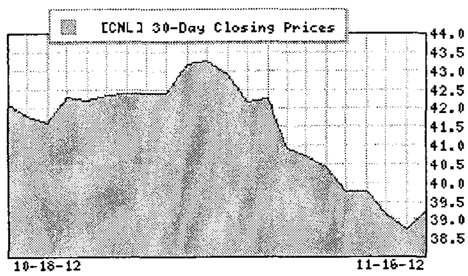
CLECO CORP
2030 DONAHUE FERRY ROAD
PINEVILLE, LA 71361-5000
Phone: 318-484-7400
Fax: 318-484-7465
Web: http://www.cleco.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/20/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	39.26
52 Week High	45.30
52 Week Low	33.80
Beta	0.46
20 Day Moving Average	279,407.66
Target Price Consensus	44



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.05	4 Week	-0.99
12 Week	-4.85	12 Week	-1.26
YTD	3.04	YTD	-4.71

Share Information		Dividend Information	
Shares Outstanding (millions)	60.72	Dividend Yield	3.44%
		Annual Dividend	$1.35
Market Capitalization (millions)	2,383.67	Payout Ratio	0.53
Short Ratio	4.10	Change in Payout Ratio	0.01
Last Split Date	05/22/2001	Last Dividend Payout / Amount	11/05/2012 / $0.34

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.34	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.43	30 Days Ago	2.75
Estimated Long-Term EPS Growth Rate	3.00	60 Days Ago	2.75
Next EPS Report Date	02/20/2013	90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.16	vs. Previous Year	-3.67%	vs. Previous Year	-15.42%
Trailing 12 Months:	15.34	vs. Previous Quarter	64.06%	vs. Previous Quarter:	23.84%
PEG Ratio	5.39				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.59	09/30/12	10.63	09/30/12	3.83

Price/Cash Flow	7.56	06/30/12	10.99	06/30/12	3.90
Price / Sales	2.39	03/31/12	10.65	03/31/12	3.72
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.48	09/30/12	1.12	09/30/12	15.47
06/30/12	1.22	06/30/12	0.88	06/30/12	14.92
03/31/12	1.59	03/31/12	1.18	03/31/12	13.85
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	25.49	09/30/12	25.49	09/30/12	24.74
06/30/12	24.80	06/30/12	24.80	06/30/12	23.90
03/31/12	27.70	03/31/12	27.70	03/31/12	23.63
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	4.15	09/30/12	0.82	09/30/12	45.17
06/30/12	4.83	06/30/12	0.85	06/30/12	46.08
03/31/12	5.33	03/31/12	0.92	03/31/12	47.87

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EMPIRE DIST ELEC CO (NYSE) — **ZACKS RANK: 2 - BUY**

EDE 20.19 -0.08 (-0.39%) Vol. 93,300 14:36 ET

The Empire District Electric Company is an operating public utility engagedin the generation, purchase, transmission, distribution and sale ofelectricity in parts of Missouri, Kansas, Oklahoma and Arkansas. TheCompany also provides water service to several towns in Missouri.

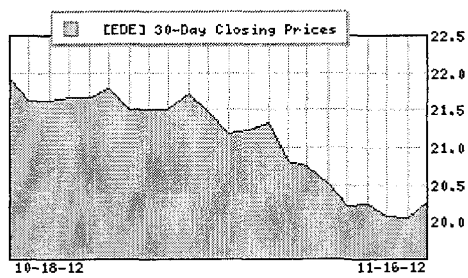
General Information

EMPIRE DISTRICT
602 JOPLIN ST
JOPLIN, MO 64802
Phone: 4176255100
Fax: 417-625-5146
Web: http://www.empiredistrict.com
Email: jwatson@empiredistrict.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/07/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.27
52 Week High	22.04
52 Week Low	19.51
Beta	0.56
20 Day Moving Average	137,000.25
Target Price Consensus	21



% Price Change

4 Week	-6.29
12 Week	-4.57
YTD	-3.89

% Price Change Relative to S&P 500

4 Week	-1.24
12 Week	-0.97
YTD	-11.12

Share Information

Shares Outstanding (millions)	42.33
Market Capitalization (millions)	858.01
Short Ratio	9.12
Last Split Date	01/30/1992

Dividend Information

Dividend Yield	4.93%
Annual Dividend	$1.00
Payout Ratio	0.78
Change in Payout Ratio	-0.21
Last Dividend Payout / Amount	08/29/2012 / $0.25

EPS Information

Current Quarter EPS Consensus Estimate	N/A
Current Year EPS Consensus Estimate	1.20
Estimated Long-Term EPS Growth Rate	-
Next EPS Report Date	02/07/2013

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00
60 Days Ago	3.00
90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.89	vs. Previous Year	0.00%	vs. Previous Year	-3.09%
Trailing 12 Months:	15.71	vs. Previous Quarter	140.00%	vs. Previous Quarter:	20.94%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.20	09/30/12	7.80	09/30/12	2.68

Price/Cash Flow	6.32	06/30/12	7.84	06/30/12	2.70
Price / Sales	1.53	03/31/12	7.73	03/31/12	2.66
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	0.81	09/30/12	0.50	09/30/12	9.76
06/30/12	0.81	06/30/12	0.51	06/30/12	9.61
03/31/12	0.88	03/31/12	0.53	03/31/12	9.38
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	15.93	09/30/12	15.93	09/30/12	16.93
06/30/12	15.71	06/30/12	15.71	06/30/12	16.59
03/31/12	15.49	03/31/12	15.49	03/31/12	16.62
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	5.51	09/30/12	0.83	09/30/12	45.31
06/30/12	5.67	06/30/12	0.85	06/30/12	45.92
03/31/12	5.89	03/31/12	0.87	03/31/12	46.45

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ENTERGY CORP NEW (NYSE)

ZACKS RANK: 3 - HOLD

ETR 62.45 ▼-0.41 (-0.65%) Vol. 665,063 14:37 ET

Entergy Corporation engages principally in the following businesses: domestic utility operations, power marketing and trading, global power development, and domestic non-utility nuclear operations. They are a major integrated energy company engaged in power production, distribution operations, and related diversified services. They are also a leading provider of wholesale energy marketing and trading services, as well as an operator of natural gas pipeline and storage facilities.

General Information

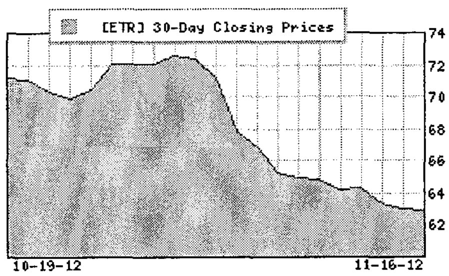
ENTERGY CORP
639 LOYOLA AVE
NEW ORLEANS, LA 70161
Phone: 5045764000
Fax: 504-576-4428
Web: http://www.entergy.com
Email: pwater1@entergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/05/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	62.86
52 Week High	74.50
52 Week Low	62.32
Beta	0.49
20 Day Moving Average	1,273,984.88
Target Price Consensus	70.06



% Price Change		% Price Change Relative to S&P 500	
4 Week	-11.75	4 Week	-6.99
12 Week	-8.54	12 Week	-5.09
YTD	-13.95	YTD	-20.42

Share Information		Dividend Information	
Shares Outstanding (millions)	177.32	Dividend Yield	5.28%
		Annual Dividend	$3.32
Market Capitalization (millions)	11,146.27	Payout Ratio	0.61
Short Ratio	4.97	Change in Payout Ratio	0.14
Last Split Date	N/A	Last Dividend Payout / Amount	11/06/2012 / $0.83

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.95	Current (1=Strong Buy, 5=Strong Sell)	2.87
Current Year EPS Consensus Estimate	5.49	30 Days Ago	2.87
Estimated Long-Term EPS Growth Rate	-1.50	60 Days Ago	2.87
Next EPS Report Date	02/05/2013	90 Days Ago	2.87

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.44	vs. Previous Year	-44.76%	vs. Previous Year	-12.72%
Trailing 12 Months:	11.56	vs. Previous Quarter	-7.58%	vs. Previous Quarter:	17.67%
PEG Ratio	-7.38				

Price Ratios **ROE** **ROA**

Price/Book	1.21	09/30/12	10.78	09/30/12	2.36
Price/Cash Flow	3.54	06/30/12	14.15	06/30/12	3.14
Price / Sales	1.08	03/31/12	13.66	03/31/12	3.03
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	0.97	09/30/12	0.68	09/30/12	9.39
06/30/12	1.05	06/30/12	0.68	06/30/12	11.76
03/31/12	1.19	03/31/12	1.12	03/31/12	10.93
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	8.95	09/30/12	8.95	09/30/12	51.83
06/30/12	8.02	06/30/12	8.02	06/30/12	50.97
03/31/12	9.83	03/31/12	9.83	03/31/12	50.27
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	7.45	09/30/12	1.28	09/30/12	55.93
06/30/12	7.96	06/30/12	1.33	06/30/12	57.20
03/31/12	8.28	03/31/12	1.36	03/31/12	57.44

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GREAT PLAINS ENERGY INCOR (NYSE)

ZACKS RANK: 3 - HOLD

GXP 20.17 ▼-0.23 (-1.13%) Vol. 572,535 14:37 ET

Great Plains Energy Incorporated engages in the generation, transmission, distribution and sale of electricity to customers located in all or portions of numerous counties in western Missouri and eastern Kansas. Customers include residences, commercial firms, and industrials, municipalities and other electric utilities.

General Information

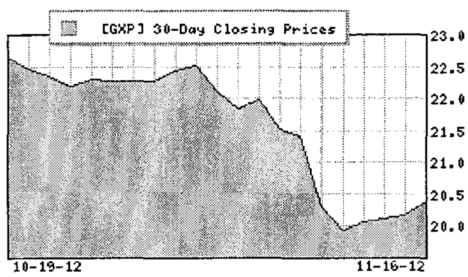
GREAT PLAINS EN
1201 WALNUT PO BOX 418679
KANSAS CITY, MO 64106-2124
Phone: 816-556-2200
Fax: 816-556-2446
Web: http://www.greatplainsenergy.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	03/04/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.40
52 Week High	22.85
52 Week Low	19.45
Beta	0.69
20 Day Moving Average	801,906.38
Target Price Consensus	23.1



% Price Change		% Price Change Relative to S&P 500	
4 Week	-9.97	4 Week	-5.12
12 Week	-4.85	12 Week	-1.26
YTD	-6.34	YTD	-13.38

Share Information		Dividend Information	
Shares Outstanding (millions)	153.43	Dividend Yield	4.17%
		Annual Dividend	$0.85
Market Capitalization (millions)	3,129.99	Payout Ratio	0.65
Short Ratio	2.35	Change in Payout Ratio	-0.10
Last Split Date	06/01/1992	Last Dividend Payout / Amount	08/27/2012 / $0.21

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.03	Current (1=Strong Buy, 5=Strong Sell)	2.33
Current Year EPS Consensus Estimate	1.31	30 Days Ago	2.33
Estimated Long-Term EPS Growth Rate	8.20	60 Days Ago	2.25
Next EPS Report Date	03/04/2013	90 Days Ago	2.56

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.61	vs. Previous Year	4.40%	vs. Previous Year	-3.55%
Trailing 12 Months:	15.69	vs. Previous Quarter	131.71%	vs. Previous Quarter:	23.62%
PEG Ratio	1.91				

Price Ratios		ROE		ROA	
Price/Book	0.93	09/30/12	6.30	09/30/12	2.12

Price/Cash Flow	5.76	06/30/12	5.86	06/30/12	1.94
Price / Sales	1.35	03/31/12	5.54	03/31/12	1.80
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	0.61	09/30/12	0.43	09/30/12	8.50
06/30/12	0.58	06/30/12	0.37	06/30/12	7.58
03/31/12	0.42	03/31/12	0.25	03/31/12	7.07
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	12.80	09/30/12	12.80	09/30/12	21.93
06/30/12	11.49	06/30/12	11.49	06/30/12	23.82
03/31/12	10.53	03/31/12	10.53	03/31/12	21.49
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	2.61	09/30/12	0.82	09/30/12	44.80
06/30/12	2.84	06/30/12	0.93	06/30/12	47.83
03/31/12	2.96	03/31/12	1.03	03/31/12	50.47

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HAWAIIAN ELECTRIC INDUS (NYSE)

ZACKS RANK: 3 - HOLD

HE 24.13 -0.08 (-0.33%) Vol. 199,558 14:37 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

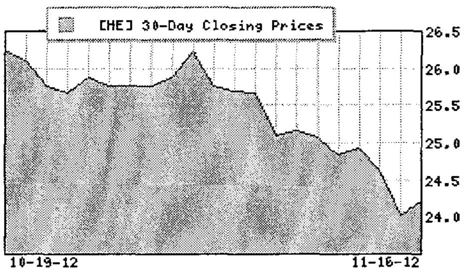
General Information

HAWAIIAN ELEC
900 RICHARDS ST
HONOLULU, HI 96813
Phone: 8085435662
Fax: 808-543-7602
Web: http://www.hei.com
Email: skimura@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/06/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.21
52 Week High	29.24
52 Week Low	23.65
Beta	0.46
20 Day Moving Average	286,236.84
Target Price Consensus	26.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.77	4 Week	-2.80
12 Week	-11.02	12 Week	-7.67
YTD	-8.57	YTD	-15.45

Share Information		Dividend Information	
Shares Outstanding (millions)	97.08	Dividend Yield	5.12%
		Annual Dividend	$1.24
Market Capitalization (millions)	2,350.35	Payout Ratio	0.75
Short Ratio	4.59	Change in Payout Ratio	-0.19
Last Split Date	06/14/2004	Last Dividend Payout / Amount	11/15/2012 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.34	Current (1=Strong Buy, 5=Strong Sell)	3.60
Current Year EPS Consensus Estimate	1.61	30 Days Ago	3.60
Estimated Long-Term EPS Growth Rate	7.00	60 Days Ago	3.60
Next EPS Report Date	02/06/2013	90 Days Ago	3.60

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.06	vs. Previous Year	-2.00%	vs. Previous Year	-2.10%
Trailing 12 Months:	14.67	vs. Previous Quarter	22.50%	vs. Previous Quarter:	1.57%
PEG Ratio	2.14				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.46	09/30/12	10.24	09/30/12	1.65

Price/Cash Flow	7.55	06/30/12	10.43	06/30/12	1.69
Price / Sales	0.69	03/31/12	9.78	03/31/12	1.59
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	0.91	09/30/12	0.91	09/30/12	4.74
06/30/12	0.91	06/30/12	0.91	06/30/12	4.74
03/31/12	0.90	03/31/12	0.90	03/31/12	4.48
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	7.35	09/30/12	7.35	09/30/12	16.55
06/30/12	7.39	06/30/12	7.39	06/30/12	16.31
03/31/12	6.91	03/31/12	6.91	03/31/12	16.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	-	09/30/12	0.89	09/30/12	47.67
06/30/12	-	06/30/12	0.91	06/30/12	48.16
03/31/12	-	03/31/12	0.83	03/31/12	45.87

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IDACORP INC (NYSE) ZACKS RANK: 2 - BUY

IDA 41.04 -0.09 (-0.22%) Vol. 69,758 14:38 ET

Idacorp Inc. is an electric public utility company. The company is engaged in the generation, purchase, transmission, distribution and sale of electric energy primarily in the areas including southern Idaho, eastern Oregon and northern Nevada. The company relies heavily on hydroelectric power for its generating needs and is one of the nation's few investor-owned utilities with a predominantly hydro base. The company's principal commercial and industrial customers include lodges, condominiums, and ski lifts and related facilities.

General Information

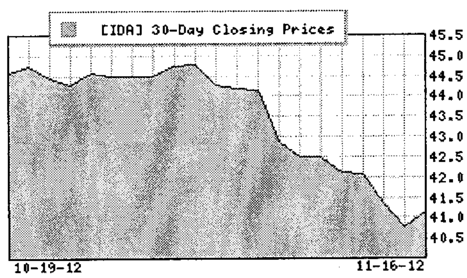
IDACORP INC
1221 WEST IDAHO STREET
BOISE, ID 83702-5627
Phone: 2083882200
Fax: 208-388-6916
Web: http://www.idacorpinc.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/20/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	41.13
52 Week High	45.67
52 Week Low	38.17
Beta	0.43
20 Day Moving Average	201,276.45
Target Price Consensus	48



% Price Change

4 Week	-7.70
12 Week	-1.70
YTD	-3.02

% Price Change Relative to S&P 500

4 Week	-2.72
12 Week	2.01
YTD	-10.31

Share Information

Shares Outstanding (millions)	50.15
Market Capitalization (millions)	2,062.88
Short Ratio	6.12
Last Split Date	N/A

Dividend Information

Dividend Yield	3.70%
Annual Dividend	$1.52
Payout Ratio	0.41
Change in Payout Ratio	-0.07
Last Dividend Payout / Amount	11/01/2012 / $0.38

EPS Information

Current Quarter EPS Consensus Estimate	0.30
Current Year EPS Consensus Estimate	3.34
Estimated Long-Term EPS Growth Rate	4.00
Next EPS Report Date	02/20/2013

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	1.60
30 Days Ago	1.75
60 Days Ago	1.33
90 Days Ago	1.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.33	vs. Previous Year	-14.81%	vs. Previous Year	7.88%
Trailing 12 Months:	12.73	vs. Previous Quarter	159.15%	vs. Previous Quarter:	31.14%
PEG Ratio	3.08				

Price Ratios **ROE** **ROA**

Price/Book	1.16	09/30/12	9.48	09/30/12	3.18
Price/Cash Flow	7.03	06/30/12	10.53	06/30/12	3.55
Price / Sales	1.95	03/31/12	9.87	03/31/12	3.33
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.36	09/30/12	0.99	09/30/12	15.21
06/30/12	1.21	06/30/12	0.84	06/30/12	17.01
03/31/12	1.14	03/31/12	0.77	03/31/12	15.93
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	16.63	09/30/12	16.63	09/30/12	35.38
06/30/12	13.72	06/30/12	13.72	06/30/12	33.86
03/31/12	11.17	03/31/12	11.17	03/31/12	33.53
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	6.42	09/30/12	0.87	09/30/12	46.41
06/30/12	6.57	06/30/12	0.91	06/30/12	47.53
03/31/12	6.87	03/31/12	0.89	03/31/12	47.03

![ZACKS INVESTMENT RESEARCH]

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NV ENERGY INC (NYSE)

ZACKS RANK: 2 - BUY

NVE 17.79 0.01 (0.06%) Vol. 1,362,119 14:39 ET

Sierra Pacific Resources, the holding company for Sierra Pacific Power Company, provide electricity to more than 286,000 customers in the area of northern Nevada and northeastern California, including world-famous Reno and Lake Tahoe. The company also provide natural gas and water service to customers in the greater Reno metropolitan area. Other operating subsidiaries of the company include the Tuscarora Gas Pipeline Company, Lands of Sierra, Sierra Energy Company, eothree and Sierra Water Development Company.

General Information

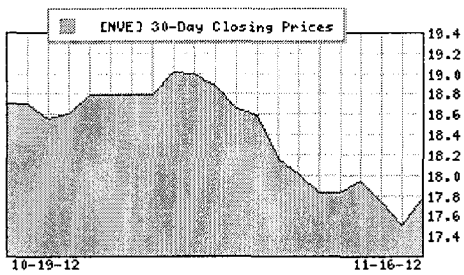
NV ENERGY INC
6226 W SAHARA AVE
LAS VEGAS, NV 89151
Phone: 7023675000
Fax: 775-834-3815
Web: http://www.nvenergy.com
Email: ir@navidea.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/19/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	17.78
52 Week High	19.20
52 Week Low	14.33
Beta	0.58
20 Day Moving Average	1,582,669.00
Target Price Consensus	19.42



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.92	4 Week	0.21
12 Week	-1.06	12 Week	2.67
YTD	8.75	YTD	0.57

Share Information		Dividend Information	
Shares Outstanding (millions)	236.00	Dividend Yield	3.82%
		Annual Dividend	$0.68
Market Capitalization (millions)	4,196.08	Payout Ratio	0.55
		Change in Payout Ratio	0.04
Short Ratio	0.67	Last Dividend Payout / Amount	08/30/2012 / $0.17
Last Split Date	07/29/1999		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.07	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	1.34	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	15.10	60 Days Ago	2.50
Next EPS Report Date	*02/19/2013*	*90 Days Ago*	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.26	vs. Previous Year	28.77%	vs. Previous Year	0.85%
Trailing 12 Months:	14.45	vs. Previous Quarter	224.14%	vs. Previous Quarter:	38.58%
PEG Ratio	0.88				

Price Ratios	ROE	ROA

Price/Book	1.17	09/30/12	8.49	09/30/12	2.49
Price/Cash Flow	7.84	06/30/12	7.12	06/30/12	2.08
Price / Sales	1.40	03/31/12	5.50	03/31/12	1.60
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.12	09/30/12	0.97	09/30/12	9.81
06/30/12	1.15	06/30/12	0.95	06/30/12	8.17
03/31/12	0.89	03/31/12	0.73	03/31/12	6.41
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	14.50	09/30/12	14.50	09/30/12	15.23
06/30/12	11.93	06/30/12	11.93	06/30/12	14.48
03/31/12	9.20	03/31/12	9.20	03/31/12	14.35
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	10.46	09/30/12	1.33	09/30/12	57.00
06/30/12	10.96	06/30/12	1.50	06/30/12	60.03
03/31/12	11.61	03/31/12	1.49	03/31/12	59.78

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PINNACLE WEST CAPITAL CORP (NYSE)

ZACKS RANK: 3 - HOLD

PNW 49.39 ▼-0.42 (-0.84%) Vol. 486,782 14:39 ET

Pinnacle West Capital is engaged, through its subsidiaries, in the generation, transmission, and distribution of electricity and selling energy, products and services; in real estate development; and in venture capital investment. Its primary subsidiary is Arizona Public Service Company. The company's other subsidiaries include SunCor, El Dorado, APSEnergy Services and Pinnacle West Energy.

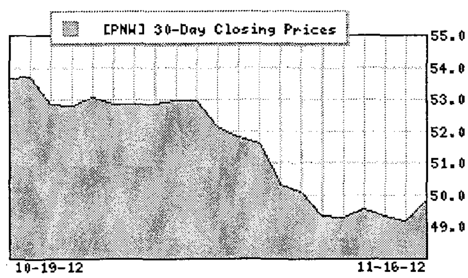
General Information

PINNACLE WEST
400 NORTH FIFTH STREET MS8695
PHOENIX, AZ 85004
Phone: 6022501000
Fax: 602-250-2430
Web: -
Email: rhickman@pinnaclewest.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/22/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	49.81
52 Week High	54.66
52 Week Low	44.19
Beta	0.51
20 Day Moving Average	610,297.13
Target Price Consensus	54



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.12	4 Week	-2.12
12 Week	-3.69	12 Week	-0.06
YTD	3.38	YTD	-4.39

Share Information		Dividend Information	
Shares Outstanding (millions)	109.54	Dividend Yield	4.38%
		Annual Dividend	$2.18
Market Capitalization (millions)	5,456.39	Payout Ratio	0.62
Short Ratio	2.58	Change in Payout Ratio	-0.18
Last Split Date	N/A	Last Dividend Payout / Amount	10/31/2012 / $1.09

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.15	Current (1=Strong Buy, 5=Strong Sell)	2.83
Current Year EPS Consensus Estimate	3.43	30 Days Ago	2.83
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.83
Next EPS Report Date	02/22/2013	90 Days Ago	2.83

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.53	vs. Previous Year	-1.34%	vs. Previous Year	-1.37%
Trailing 12 Months:	14.78	vs. Previous Quarter	97.32%	vs. Previous Quarter:	26.28%
PEG Ratio	2.41				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.30	09/30/12	9.38	09/30/12	2.81

Price/Cash Flow	8.16	06/30/12	9.52	06/30/12	2.84
Price / Sales	1.67	03/31/12	8.67	03/31/12	2.59
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.16	09/30/12	0.89	09/30/12	11.36
06/30/12	0.86	06/30/12	0.63	06/30/12	11.34
03/31/12	0.78	03/31/12	0.57	03/31/12	10.46
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	19.23	09/30/12	19.23	09/30/12	38.21
06/30/12	18.68	06/30/12	18.68	06/30/12	35.62
03/31/12	17.16	03/31/12	17.16	03/31/12	35.34
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	7.78	09/30/12	0.80	09/30/12	44.37
06/30/12	8.06	06/30/12	0.86	06/30/12	46.37
03/31/12	8.18	03/31/12	0.87	03/31/12	46.39

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PNM RESOURCES INC (NYSE)

ZACKS RANK: 2 - BUY

PNM 20.25 -0.05 (-0.25%) Vol. 156,205 14:40 ET

PNM Resources is an energy holding company based in Albuquerque, New Mexico. Its principal subsidiary is Public Service Company of New Mexico, which provides electric power and natural gas utility services to more than 1.3 million people in New Mexico. The company also sells power on the wholesale market in the Western U.S.

General Information

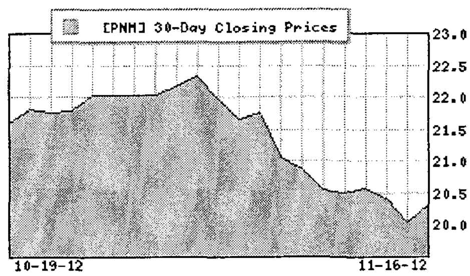
PNM RESOURCES
ALVARADO SQUARE NEW MEXICO
ALBUQUERQUE, NM 87158
Phone: 5052412700
Fax: 505-241-4311
Web: http://www.pnmresources.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	03/06/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.30
52 Week High	22.54
52 Week Low	16.99
Beta	0.89
20 Day Moving Average	367,562.34
Target Price Consensus	23.1



% Price Change

4 Week	-6.06
12 Week	-1.12
YTD	11.35

% Price Change Relative to S&P 500

4 Week	-1.00
12 Week	2.61
YTD	2.98

Share Information

Shares Outstanding (millions)	79.65
Market Capitalization (millions)	1,616.98
Short Ratio	5.00
Last Split Date	06/14/2004

Dividend Information

Dividend Yield	2.86%
Annual Dividend	$0.58
Payout Ratio	0.41
Change in Payout Ratio	-0.47
Last Dividend Payout / Amount	10/31/2012 / $0.29

EPS Information

Current Quarter EPS Consensus Estimate	0.12
Current Year EPS Consensus Estimate	1.30
Estimated Long-Term EPS Growth Rate	8.20
Next EPS Report Date	03/06/2013

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.75
30 Days Ago	2.71
60 Days Ago	2.75
90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.60	vs. Previous Year	13.11%	vs. Previous Year	-28.95%
Trailing 12 Months:	14.40	vs. Previous Quarter	109.09%	vs. Previous Quarter:	20.55%
PEG Ratio	1.90				

Price Ratios		ROE		ROA	
Price/Book	0.94	09/30/12	6.78	09/30/12	2.18

Price/Cash Flow	5.54	06/30/12	6.87	06/30/12	2.18
Price / Sales	1.18	03/31/12	6.42	03/31/12	2.02
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.20	09/30/12	1.05	09/30/12	8.32
06/30/12	1.04	06/30/12	0.91	06/30/12	7.51
03/31/12	1.00	03/31/12	0.86	03/31/12	6.57
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	26.46	09/30/12	26.46	09/30/12	21.51
06/30/12	22.29	06/30/12	22.29	06/30/12	21.10
03/31/12	19.34	03/31/12	19.34	03/31/12	20.87
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	10.07	09/30/12	0.98	09/30/12	49.22
06/30/12	12.92	06/30/12	0.99	06/30/12	49.70
03/31/12	14.88	03/31/12	1.01	03/31/12	50.31

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PORTLAND GENERAL ELECTRIC CO (NYSE)

ZACKS RANK: 3 - HOLD

POR 25.48 ▲0.15 (0.59%) Vol. 634,278 14:40 ET

Portland General Electric, headquartered in Portland, Ore., is a vertically integrated electric utility that serves residential, commercial and industrial customers in Oregon. The company has more than a century of experience in power delivery. PGE generates power from a diverse mix of resources, including hydropower, coal and natural gas. PGE also participates in the wholesale market by purchasing and selling electricity and natural gas to utilities and energy marketers.

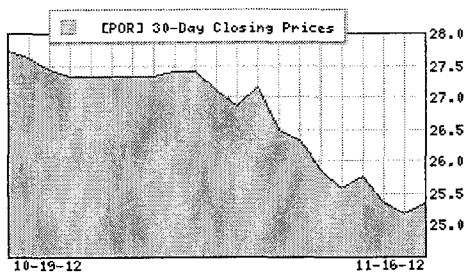
General Information

PORTLAND GEN EL
121 SW SALMON ST 1WTC0501
PORTLAND, OR 97204
Phone: 5034647779
Fax: 503-464-2676
Web: http://www.portlandgeneral.com/
Email: investors@pgn.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/22/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.33
52 Week High	28.08
52 Week Low	23.48
Beta	0.65
20 Day Moving Average	408,830.44
Target Price Consensus	27.69



% Price Change		% Price Change Relative to S&P 500	
4 Week	-8.65	4 Week	-3.73
12 Week	-6.15	12 Week	-2.61
YTD	0.16	YTD	-7.38

Share Information		Dividend Information	
Shares Outstanding (millions)	75.53	Dividend Yield	4.26%
		Annual Dividend	$1.08
Market Capitalization (millions)	1,913.12	Payout Ratio	0.57
Short Ratio	3.98	Change in Payout Ratio	-0.03
Last Split Date	N/A	Last Dividend Payout / Amount	09/21/2012 / $0.27

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.44	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	1.91	30 Days Ago	2.44
Estimated Long-Term EPS Growth Rate	4.10	60 Days Ago	2.63
Next EPS Report Date	02/22/2013	90 Days Ago	2.63

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.25	vs. Previous Year	38.89%	vs. Previous Year	2.51%
Trailing 12 Months:	13.47	vs. Previous Quarter	47.06%	vs. Previous Quarter:	8.96%
PEG Ratio	3.24				

Price Ratios	ROE	ROA

Price/Book	1.11	09/30/12	8.38	09/30/12	2.47
Price/Cash Flow	5.10	06/30/12	7.80	06/30/12	2.29
Price / Sales	1.05	03/31/12	7.62	03/31/12	2.24
Current Ratio		***Quick Ratio***		**Operating Margin**	
09/30/12	1.21	09/30/12	1.09	09/30/12	7.80
06/30/12	1.29	06/30/12	1.14	06/30/12	7.24
03/31/12	1.33	03/31/12	1.19	03/31/12	7.02
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	10.98	09/30/12	10.98	09/30/12	22.76
06/30/12	10.06	06/30/12	10.06	06/30/12	22.53
03/31/12	9.85	03/31/12	9.85	03/31/12	22.49
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	12.32	09/30/12	0.89	09/30/12	47.19
06/30/12	12.70	06/30/12	0.93	06/30/12	48.25
03/31/12	13.80	03/31/12	0.96	03/31/12	49.10

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SOUTHERN CO (NYSE)					ZACKS RANK: 3 - HOLD
SO	42.64	-0.05	(-0.12%)	Vol. 3,102,199	14:41 ET

Southern Energy acquires, develops, builds, owns and operates power production and delivery facilities and provides a broad range ofenergy-related services to utilities and industrial companies in selectedcountries around the world. Southern Energy businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

General Information

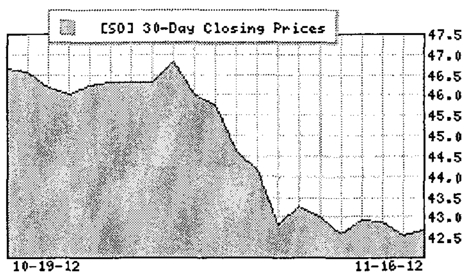
SOUTHN COMPANY
30 IVAN ALLEN JR. BLVD. N.W.
ATLANTA, GA 30308
Phone: 4045065000
Fax: 404-506-0455
Web: http://www.southernco.com
Email: dstucker@southernco.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	01/23/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	42.69
52 Week High	48.59
52 Week Low	42.11
Beta	0.26
20 Day Moving Average	5,289,830.50
Target Price Consensus	46.9



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	-8.47	4 Week	-3.53
12 Week	-6.95	12 Week	-3.45
YTD	-7.78	YTD	-14.71

Share Information		**Dividend Information**	
Shares Outstanding (millions)	874.80	Dividend Yield	4.59%
		Annual Dividend	$1.96
Market Capitalization (millions)	37,345.09	Payout Ratio	0.78
Short Ratio	2.61	Change in Payout Ratio	0.03
Last Split Date	03/01/1994	Last Dividend Payout / Amount	11/01/2012 / $0.49

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.40	Current (1=Strong Buy, 5=Strong Sell)	3.06
Current Year EPS Consensus Estimate	2.63	30 Days Ago	3.13
Estimated Long-Term EPS Growth Rate	5.20	60 Days Ago	3.13
Next EPS Report Date	01/23/2013	90 Days Ago	3.13

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.22	vs. Previous Year	3.74%	vs. Previous Year	-7.02%
Trailing 12 Months:	16.94	vs. Previous Quarter	60.87%	vs. Previous Quarter:	20.76%
PEG Ratio	3.11				

Price Ratios		**ROE**		**ROA**	
Price/Book	2.00	09/30/12	12.43	09/30/12	3.70

Price/Cash Flow	8.53	06/30/12	12.27	06/30/12	3.67
Price / Sales	2.26	03/31/12	12.48	03/31/12	3.75
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.02	09/30/12	0.63	09/30/12	13.55
06/30/12	1.05	06/30/12	0.62	06/30/12	12.89
03/31/12	0.96	03/31/12	0.56	03/31/12	12.64
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	21.10	09/30/12	21.10	09/30/12	21.31
06/30/12	20.12	06/30/12	20.12	06/30/12	20.86
03/31/12	19.73	03/31/12	19.73	03/31/12	20.53
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	0.69	09/30/12	1.02	09/30/12	49.01
06/30/12	0.95	06/30/12	1.07	06/30/12	50.33
03/31/12	1.16	03/31/12	1.08	03/31/12	50.36

Zacks Investment Research
Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

WESTERN ENERGY INC (NYSE) ZACKS RANK: 2 - BUY

WR 27.86 -0.04 (-0.14%) Vol. 360,435 14:42 ET

Westar Energy is a consumer services company with interests in monitored services and energy. Westar Energy provides electric utility services to customers in Kansas. Westar Energy's goal is to operate the best utility in the Midwest. They will provide their customers quality service at below average prices. Westar Energy Generation and Marketing will be a preferred energy provider, both inside and outside their service territory.

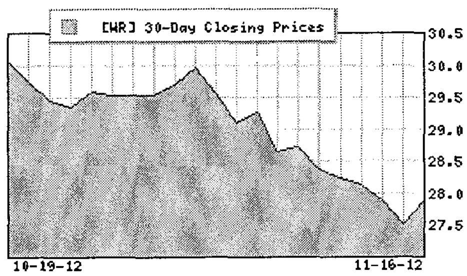
General Information

WESTAR ENERGY
818 S KANSAS AVE
TOPEKA, KS 66601
Phone: 785-575-6300
Fax: 785-575-6596
Web: http://www.westarenergy.com
Email: ir@westarenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	02/21/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	27.90
52 Week High	33.04
52 Week Low	25.79
Beta	0.56
20 Day Moving Average	522,266.84
Target Price Consensus	32



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.22	4 Week	-2.21
12 Week	-4.58	12 Week	-0.99
YTD	-3.06	YTD	-10.35

Share Information		Dividend Information	
Shares Outstanding (millions)	126.32	Dividend Yield	4.73%
		Annual Dividend	$1.32
Market Capitalization (millions)	3,524.19	Payout Ratio	0.68
Short Ratio	4.27	Change in Payout Ratio	-0.15
Last Split Date	N/A	Last Dividend Payout / Amount	09/05/2012 / $0.33

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.23	Current (1=Strong Buy, 5=Strong Sell)	2.11
Current Year EPS Consensus Estimate	1.97	30 Days Ago	2.11
Estimated Long-Term EPS Growth Rate	5.70	60 Days Ago	2.25
Next EPS Report Date	02/21/2013	90 Days Ago	2.11

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.20	vs. Previous Year	12.24%	vs. Previous Year	2.60%
Trailing 12 Months:	14.31	vs. Previous Quarter	129.17%	vs. Previous Quarter:	22.87%
PEG Ratio	2.50				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.22	09/30/12	8.87	09/30/12	2.79

Price/Cash Flow	6.06	06/30/12	8.20	06/30/12	2.57
Price / Sales	1.58	03/31/12	7.75	03/31/12	2.40
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	0.92	09/30/12	0.58	09/30/12	11.20
06/30/12	0.84	06/30/12	0.54	06/30/12	10.17
03/31/12	0.72	03/31/12	0.43	03/31/12	9.50
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	16.72	09/30/12	16.72	09/30/12	22.95
06/30/12	16.43	06/30/12	16.43	06/30/12	22.14
03/31/12	15.46	03/31/12	15.46	03/31/12	21.96
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	4.87	09/30/12	1.06	09/30/12	51.37
06/30/12	5.12	06/30/12	1.09	06/30/12	52.13
03/31/12	5.24	03/31/12	1.05	03/31/12	50.93

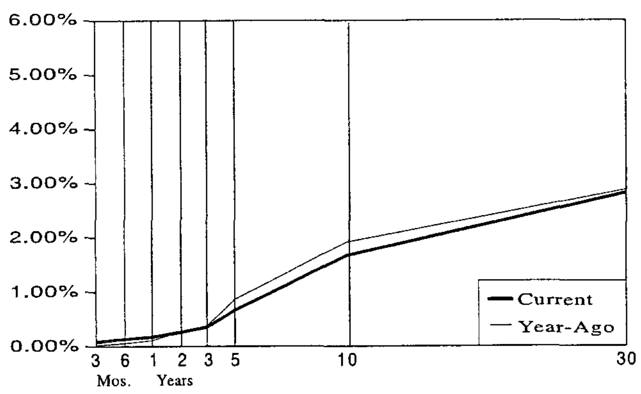
ATTACHMENT C

Selected Yields

	Recent (11/20/12)	3 Months Ago (8/22/12)	Year Ago (11/22/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.22	0.31	0.44
3-month LIBOR	0.31	0.43	0.50
Bank CDs			
6-month	0.11	0.17	0.17
1-year	0.16	0.21	0.21
5-year	0.76	0.96	1.14
U.S. Treasury Securities			
3-month	0.09	0.10	0.02
6-month	0.14	0.13	0.06
1-year	0.18	0.18	0.11
5-year	0.67	0.70	0.87
10-year	1.67	1.70	1.92
10-year (inflation-protected)	-0.76	-0.58	0.01
30-year	2.82	2.82	2.88
30-year Zero	3.04	3.00	3.05

	Recent (11/20/12)	3 Months Ago (8/22/12)	Year Ago (11/22/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.73	0.96	1.25
FHLMC 5.5% (Gold)	2.09	2.12	2.33
FNMA 5.5%	1.73	1.94	2.05
FNMA ARM	2.19	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.91	3.09	4.45
Industrial (25/30-year) A	3.78	3.82	4.20
Utility (25/30-year) A	3.78	3.85	4.06
Utility (25/30-year) Baa/BBB	4.13	4.28	4.74
Foreign Bonds (10-Year)			
Canada	1.76	1.84	2.08
Germany	1.42	1.46	1.92
Japan	0.74	0.83	0.97
United Kingdom	1.85	1.63	2.17
Preferred Stocks			
Utility A	5.12	5.32	5.84
Financial BBB	6.09	6.08	6.31
Financial Adjustable A	5.52	5.52	5.52

Treasury Security Yield Curve



	Recent (11/20/12)	3 Months Ago (8/22/12)	Year Ago (11/22/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.41	3.80	4.09
25-Bond Index (Revs)	4.17	4.52	5.09
General Obligation Bonds (GOs)			
1-year Aaa	0.17	0.20	0.24
1-year A	0.78	0.88	1.06
5-year Aaa	0.67	0.79	1.22
5-year A	1.65	1.85	2.33
10-year Aaa	1.76	2.06	2.48
10-year A	2.80	3.19	3.53
25/30-year Aaa	3.13	3.36	3.97
25/30-year A	4.70	4.79	5.34
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.18	4.27	4.60
Electric AA	4.27	4.55	4.82
Housing AA	4.64	4.73	5.53
Hospital AA	4.30	4.48	4.92
Toll Road Aaa	4.22	4.31	4.58

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	11/14/12	10/31/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1438804	1422943	15861	1430434	1449840	1479638
Borrowed Reserves	1128	1363	-235	1961	3513	5862
Net Free/Borrowed Reserves	1437676	1421580	16096	1428473	1446327	1473776

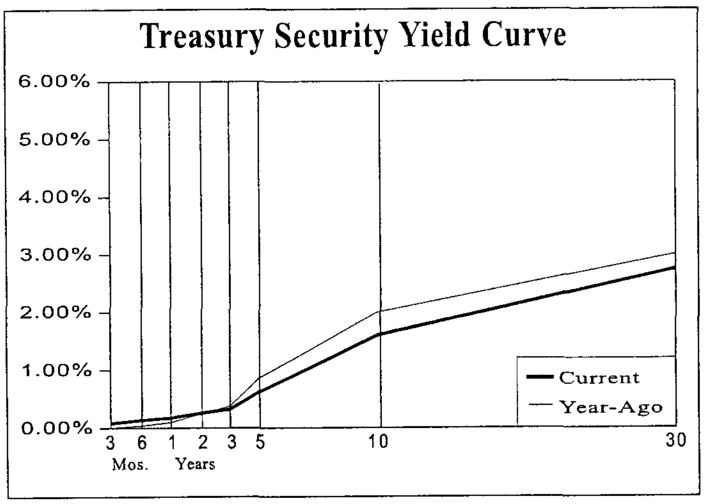
MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	11/5/12	10/29/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2420.9	2419.4	1.5	20.3%	15.9%	13.6%
M2 (M1+savings+small time deposits)	10291.9	10255.5	36.4	12.1%	8.5%	7.6%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (11/14/12)	3 Months Ago (8/15/12)	Year Ago (11/16/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.21	0.47
3-month LIBOR	0.31	0.43	0.47
Bank CDs			
6-month	0.11	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.76	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.08	0.01
6-month	0.14	0.14	0.04
1-year	0.18	0.18	0.10
5-year	0.63	0.80	0.87
10-year	1.60	1.82	2.00
10-year (inflation-protected)	-0.84	-0.45	0.03
30-year	2.74	2.92	3.00
30-year Zero	2.95	3.12	3.21



	Recent (11/14/12)	3 Months Ago (8/15/12)	Year Ago (11/16/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.95	1.03	1.25
FHLMC 5.5% (Gold)	2.15	1.89	2.35
FNMA 5.5%	1.74	1.69	2.09
FNMA ARM	2.20	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.79	3.23	4.38
Industrial (25/30-year) A	3.67	3.96	4.31
Utility (25/30-year) A	3.66	3.95	4.17
Utility (25/30-year) Baa/BBB	4.00	4.39	4.85
Foreign Bonds (10-Year)			
Canada	1.70	1.95	2.10
Germany	1.34	1.56	1.82
Japan	0.75	0.82	0.95
United Kingdom	1.75	1.68	2.16
Preferred Stocks			
Utility A	5.11	5.31	5.26
Financial BBB	6.09	6.07	6.30
Financial Adjustable A	5.51	5.51	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.55	3.75	4.02
25-Bond Index (Revs)	4.23	4.50	5.00
General Obligation Bonds (GOs)			
1-year Aaa	0.22	0.17	0.24
1-year A	0.82	0.85	1.07
5-year Aaa	0.68	0.77	1.26
5-year A	1.67	1.83	2.33
10-year Aaa	1.84	1.96	2.50
10-year A	2.89	3.10	3.51
25/30-year Aaa	3.20	3.31	4.01
25/30-year A	4.72	4.78	5.38
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.20	4.21	4.56
Electric AA	4.29	4.49	4.89
Housing AA	4.66	4.67	5.57
Hospital AA	4.35	4.46	4.93
Toll Road Aaa	4.24	4.30	4.57

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 10/31/12	Recent Levels 10/17/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1422945	1423709	-764	1439552	1451187	1482492
Borrowed Reserves	1363	1527	-164	2325	3906	6227
Net Free/Borrowed Reserves	1421582	1422182	-600	1437227	1447281	1476265

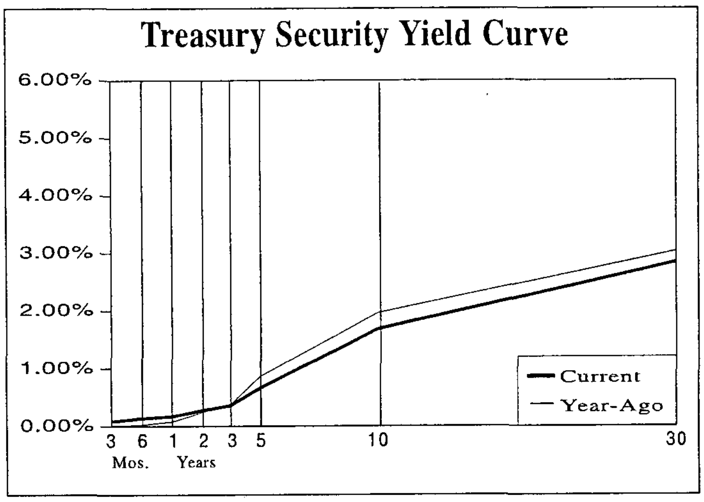
MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 10/29/12	Recent Levels 10/22/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2419.5	2401.6	17.9	18.1%	15.3%	13.3%
M2 (M1+savings+small time deposits)	10257.3	10211.8	45.5	9.8%	7.7%	7.4%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (11/07/12)	3 Months Ago (8/08/12)	Year Ago (11/09/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.30	0.49
3-month LIBOR	0.31	0.44	0.45
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.81	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.11	0.01
6-month	0.14	0.14	0.03
1-year	0.17	0.18	0.08
5-year	0.67	0.73	0.87
10-year	1.68	1.65	1.96
10-year (inflation-protected)	-0.82	-0.63	-0.05
30-year	2.84	2.75	3.03
30-year Zero	3.05	2.95	3.25



	Recent (11/07/12)	3 Months Ago (8/08/12)	Year Ago (11/09/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.53	0.96	1.37
FHLMC 5.5% (Gold)	1.83	1.72	2.35
FNMA 5.5%	1.42	1.52	2.03
FNMA ARM	2.19	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.90	3.16	4.09
Industrial (25/30-year) A	3.71	3.83	4.23
Utility (25/30-year) A	3.77	3.81	4.14
Utility (25/30-year) Baa/BBB	4.12	4.24	4.83
Foreign Bonds (10-Year)			
Canada	1.75	1.82	2.09
Germany	1.38	1.42	1.72
Japan	0.76	0.80	0.98
United Kingdom	1.76	1.57	2.18
Preferred Stocks			
Utility A	5.11	5.11	5.82
Financial BBB	6.08	5.90	5.70
Financial Adjustable A	5.51	5.51	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.67	3.66	4.02
25-Bond Index (Revs)	4.29	4.46	5.05
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.18	0.25
1-year A	0.83	0.87	1.06
5-year Aaa	0.74	0.73	1.27
5-year A	1.72	1.79	2.33
10-year Aaa	1.95	1.91	2.51
10-year A	3.01	3.05	3.52
25/30-year Aaa	3.28	3.29	4.01
25/30-year A	4.79	4.78	5.35
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.17	4.56
Electric AA	4.33	4.53	4.90
Housing AA	4.70	4.67	5.58
Hospital AA	4.42	4.44	4.92
Toll Road Aaa	4.27	4.30	4.55

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/31/12	**10/17/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1422927	1423708	-781	1439550	1451186	1482491
Borrowed Reserves	1363	1527	-164	2325	3906	6227
Net Free/Borrowed Reserves	1421564	1422181	-617	1437225	1447280	1476264

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

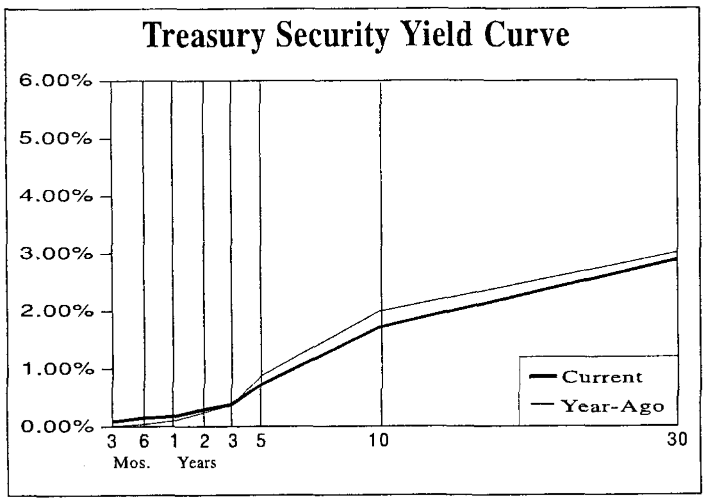
	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/22/12	**10/15/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2401.7	2386.8	14.9	16.6%	13.8%	12.2%
M2 (M1+savings+small time deposits)	10211.8	10210.8	1.0	8.1%	8.0%	7.2%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/31/12)	3 Months Ago (8/01/12)	Year Ago (11/02/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.24	0.30	0.51
3-month LIBOR	0.31	0.44	0.43
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.81	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.09	0.01
6-month	0.15	0.14	0.04
1-year	0.18	0.17	0.10
5-year	0.73	0.64	0.88
10-year	1.71	1.55	1.99
10-year (inflation-protected)	-0.81	-0.69	-0.10
30-year	2.89	2.62	3.01
30-year Zero	3.08	2.79	3.22

	Recent (10/31/12)	3 Months Ago (8/01/12)	Year Ago (11/02/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.42	0.93	1.62
FHLMC 5.5% (Gold)	1.76	1.63	2.34
FNMA 5.5%	1.42	1.53	2.10
FNMA ARM	2.27	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.96	3.04	4.15
Industrial (25/30-year) A	3.77	3.72	4.18
Utility (25/30-year) A	3.83	3.69	4.12
Utility (25/30-year) Baa/BBB	4.20	4.13	4.76
Foreign Bonds (10-Year)			
Canada	1.79	1.71	2.17
Germany	1.46	1.37	1.83
Japan	0.78	0.78	1.00
United Kingdom	1.85	1.52	2.29
Preferred Stocks			
Utility A	5.10	5.12	5.82
Financial BBB	6.06	5.92	6.57
Financial Adjustable A	5.50	5.50	5.50



	Recent (10/31/12)	3 Months Ago (8/01/12)	Year Ago (11/02/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.68	3.61	4.12
25-Bond Index (Revs)	4.33	4.44	5.10
General Obligation Bonds (GOs)			
1-year Aaa	0.22	0.17	0.24
1-year A	0.84	0.90	1.05
5-year Aaa	0.73	0.73	1.28
5-year A	1.71	1.79	2.35
10-year Aaa	1.95	1.84	2.57
10-year A	3.02	2.99	3.56
25/30-year Aaa	3.29	3.27	4.03
25/30-year A	4.80	4.75	5.37
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.13	4.55
Electric AA	4.33	4.49	4.90
Housing AA	4.70	4.61	5.59
Hospital AA	4.43	4.44	4.94
Toll Road Aaa	4.27	4.35	4.55

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/17/12	**10/3/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1423708	1371236	52472	1449745	1457405	1488008
Borrowed Reserves	1527	1662	-135	2734	4309	6596
Net Free/Borrowed Reserves	1422181	1369574	52607	1447011	1453096	1481412

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

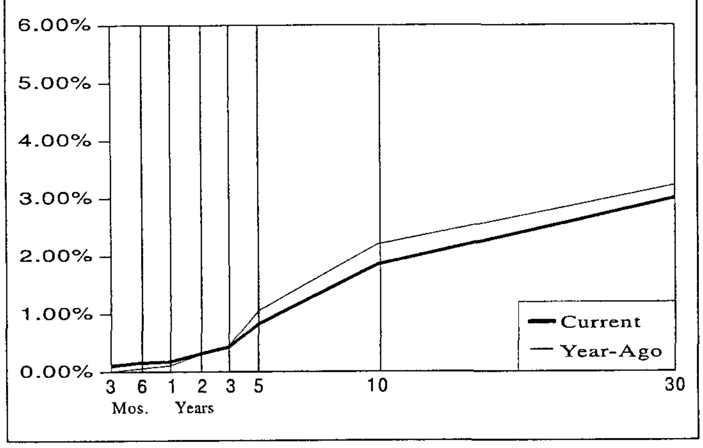
	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/15/12	**10/8/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2386.9	2371.5	15.4	17.8%	13.3%	11.6%
M2 (M1+savings+small time deposits)	10211.3	10182.4	28.9	7.9%	7.1%	7.2%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/24/12)	3 Months Ago (7/25/12)	Year Ago (10/26/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.32	0.49
3-month LIBOR	0.31	0.45	0.42
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.81	1.09	1.14
U.S. Treasury Securities			
3-month	0.11	0.10	0.01
6-month	0.16	0.14	0.06
1-year	0.18	0.17	0.11
5-year	0.83	0.58	1.06
10-year	1.85	1.42	2.20
10-year (inflation-protected)	-0.69	-0.68	0.12
30-year	3.00	2.48	3.22
30-year Zero	3.17	2.64	3.43
Mortgage-Backed Securities			
GNMA 5.5%	1.40	1.06	1.76
FHLMC 5.5% (Gold)	1.85	1.52	2.39
FNMA 5.5%	1.48	1.54	2.19
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.07	3.00	4.41
Industrial (25/30-year) A	3.81	3.62	4.49
Utility (25/30-year) A	3.85	3.59	4.41
Utility (25/30-year) Baa/BBB	4.23	4.01	5.05
Foreign Bonds (10-Year)			
Canada	1.85	1.59	2.38
Germany	1.56	1.26	2.04
Japan	0.78	0.73	1.00
United Kingdom	1.85	1.46	2.47
Preferred Stocks			
Utility A	5.10	5.23	5.21
Financial BBB	6.06	5.92	6.49
Financial Adjustable A	5.50	5.50	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.68	3.75	4.08
25-Bond Index (Revs)	4.33	4.51	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.19	0.29
1-year A	0.86	0.90	1.00
5-year Aaa	0.73	0.75	1.41
5-year A	1.70	1.80	2.42
10-year Aaa	1.95	1.87	2.69
10-year A	3.04	2.98	3.60
25/30-year Aaa	3.30	3.29	4.10
25/30-year A	4.81	4.74	5.42
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.16	4.56
Electric AA	4.32	4.52	4.94
Housing AA	4.69	4.64	5.66
Hospital AA	4.43	4.44	4.97
Toll Road Aaa	4.26	4.32	4.57

Treasury Security Yield Curve



Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/17/12	**10/3/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1423713	1371238	52475	1449746	1457406	1488008
Borrowed Reserves	1527	1662	-135	2734	4309	6596
Net Free/Borrowed Reserves	1422186	1369576	52610	1447012	1453097	1481412

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

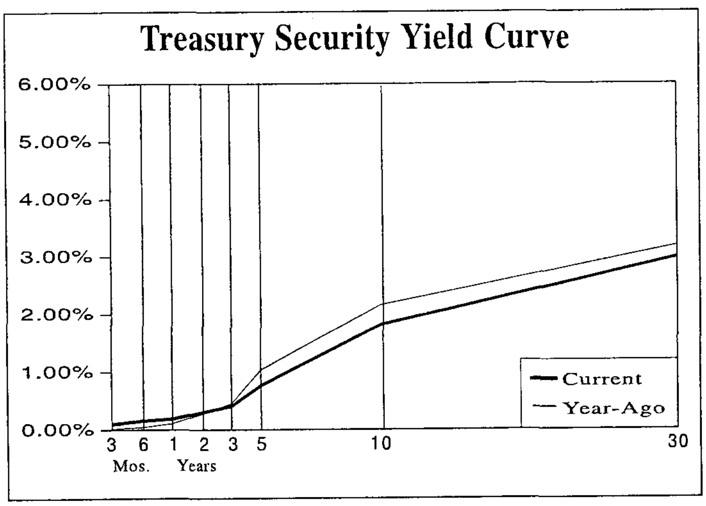
	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/8/12	**10/1/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2371.4	2374.1	-2.7	18.9%	13.0%	11.1%
M2 (M1+savings+small time deposits)	10182.4	10194.9	-12.5	8.5%	7.0%	7.1%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/17/12)	3 Months Ago (7/18/12)	Year Ago (10/19/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.25	0.26	0.44
3-month LIBOR	0.32	0.46	0.41
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.86	1.09	1.14
U.S. Treasury Securities			
3-month	0.10	0.09	0.02
6-month	0.16	0.13	0.05
1-year	0.19	0.16	0.11
5-year	0.77	0.61	1.04
10-year	1.81	1.50	2.16
10-year (inflation-protected)	-0.67	-0.64	0.20
30-year	2.98	2.60	3.18
30-year Zero	3.23	2.80	3.38

	Recent (10/17/12)	3 Months Ago (7/18/12)	Year Ago (10/19/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.05	1.13	1.84
FHLMC 5.5% (Gold)	1.89	1.61	2.36
FNMA 5.5%	1.54	1.60	2.17
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.10	3.11	4.33
Industrial (25/30-year) A	3.88	3.78	4.53
Utility (25/30-year) A	3.94	3.74	4.40
Utility (25/30-year) Baa/BBB	4.27	4.17	4.92
Foreign Bonds (10-Year)			
Canada	1.81	1.62	2.33
Germany	1.63	1.20	2.06
Japan	0.77	0.76	1.02
United Kingdom	1.92	1.48	2.47
Preferred Stocks			
Utility A	5.09	5.39	5.25
Financial BBB	6.05	6.51	6.69
Financial Adjustable A	5.49	5.49	5.49



	Recent (10/17/12)	3 Months Ago (7/18/12)	Year Ago (10/19/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.64	3.83	4.17
25-Bond Index (Revs)	4.32	4.56	5.06
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.19	0.25
1-year A	0.84	0.89	1.08
5-year Aaa	0.68	0.79	1.39
5-year A	1.67	1.88	2.40
10-year Aaa	1.89	1.92	2.69
10-year A	3.01	3.03	3.67
25/30-year Aaa	3.28	3.35	4.09
25/30-year A	4.79	4.77	5.45
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.23	4.26	4.56
Electric AA	4.31	4.58	4.94
Housing AA	4.68	4.72	5.64
Hospital AA	4.41	4.50	4.97
Toll Road Aaa	4.23	4.35	4.57

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 10/3/12	9/19/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1371241	1424682	-53441	1454652	1462067	1492376
Borrowed Reserves	1662	2007	-345	3176	4706	6963
Net Free/Borrowed Reserves	1369579	1422675	-53096	1451477	1457362	1485413

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

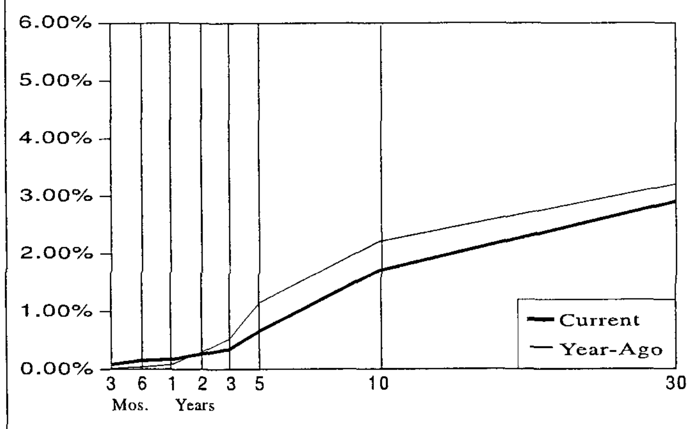
	Recent Levels 10/1/12	9/24/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2374.3	2391.1	-16.8	22.7%	13.8%	11.6%
M2 (M1+savings+small time deposits)	10197.0	10123.0	74.0	9.1%	7.2%	7.2%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/10/12)	3 Months Ago (7/11/12)	Year Ago (10/12/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.26	0.36	0.38
3-month LIBOR	0.34	0.46	0.40
Bank CDs			
6-month	0.13	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.86	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.09	0.02
6-month	0.15	0.15	0.04
1-year	0.17	0.19	0.08
5-year	0.66	0.64	1.15
10-year	1.70	1.52	2.21
10-year (inflation-protected)	-0.83	-0.61	0.23
30-year	2.90	2.61	3.20
30-year Zero	3.11	2.81	3.39

Treasury Security Yield Curve



	Recent (10/10/12)	3 Months Ago (7/11/12)	Year Ago (10/12/11)
Mortgage-Backed Securities			
GNMA 5.5%	0.78	1.17	1.89
FHLMC 5.5% (Gold)	1.84	1.66	2.32
FNMA 5.5%	1.52	1.60	2.17
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.03	3.19	4.37
Industrial (25/30-year) A	3.80	3.82	4.59
Utility (25/30-year) A	3.84	3.80	4.53
Utility (25/30-year) Baa/BBB	4.15	4.25	4.99
Foreign Bonds (10-Year)			
Canada	1.79	1.68	2.35
Germany	1.49	1.27	2.19
Japan	0.77	0.79	1.00
United Kingdom	1.77	1.57	2.64
Preferred Stocks			
Utility A	5.09	5.38	5.57
Financial BBB	6.04	6.41	6.81
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.61	3.94	4.14
25-Bond Index (Revs)	4.28	4.65	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.20	0.26
1-year A	0.83	0.89	1.11
5-year Aaa	0.67	0.82	1.41
5-year A	1.66	1.90	2.43
10-year Aaa	1.87	2.01	2.63
10-year A	2.99	3.09	3.75
25/30-year Aaa	3.29	3.47	4.12
25/30-year A	4.79	4.84	5.50
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.23	4.30	4.59
Electric AA	4.31	4.62	4.97
Housing AA	4.68	4.76	5.63
Hospital AA	4.41	4.55	5.00
Toll Road Aaa	4.23	4.39	4.60

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/3/12	**9/19/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1371232	1425102	-53870	1454711	1462097	1492391
Borrowed Reserves	1662	2007	-345	3176	4706	6963
Net Free/Borrowed Reserves	1369570	1423095	-53525	1451536	1457391	1485429

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

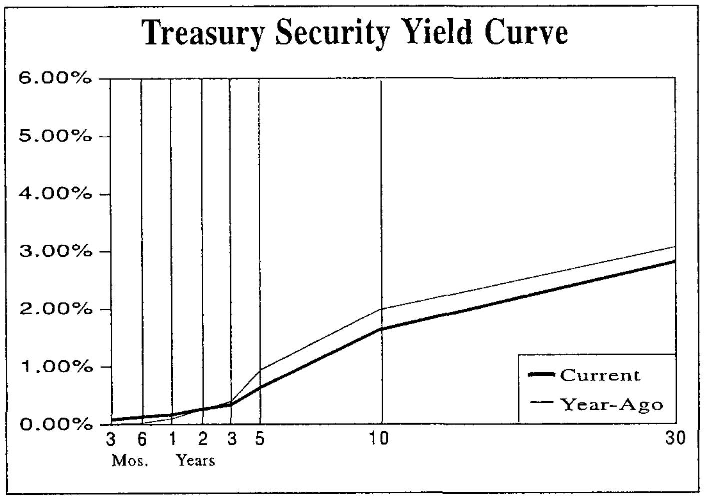
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/24/12	**9/17/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2393.3	2385.9	7.4	27.2%	16.2%	13.0%
M2 (M1+savings+small time deposits)	10138.2	10138.1	0.1	7.8%	6.4%	6.7%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.28	0.26	0.41
3-month LIBOR	0.35	0.46	0.38
Bank CDs			
6-month	0.13	0.20	0.17
1-year	0.16	0.32	0.21
5-year	0.86	1.09	1.18
U.S. Treasury Securities			
3-month	0.09	0.08	0.01
6-month	0.13	0.15	0.02
1-year	0.16	0.20	0.09
5-year	0.62	0.70	0.95
10-year	1.57	1.63	1.89
10-year (inflation-protected)	-0.90	-0.51	0.08
30-year	2.68	2.74	2.85
30-year Zero	3.08	2.95	3.03

	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
Mortgage-Backed Securities			
GNMA 5.5%	0.77	1.39	1.54
FHLMC 5.5% (Gold)	2.00	1.92	2.23
FNMA 5.5%	1.69	1.84	2.13
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.00	3.33	3.88
Industrial (25/30-year) A	3.78	3.99	4.29
Utility (25/30-year) A	3.84	3.93	4.21
Utility (25/30-year) Baa/BBB	4.16	4.37	4.65
Foreign Bonds (10-Year)			
Canada	1.74	1.71	2.14
Germany	1.47	1.45	1.84
Japan	0.77	0.82	0.97
United Kingdom	1.72	1.72	2.36
Preferred Stocks			
Utility A	5.14	5.39	5.29
Financial BBB	6.51	6.53	6.51
Financial Adjustable A	5.48	5.48	5.48



	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.67	3.95	3.93
25-Bond Index (Revs)	4.31	4.69	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.19	0.19	0.20
1-year A	0.82	0.91	0.97
5-year Aaa	0.69	0.86	1.13
5-year A	1.62	1.91	2.18
10-year Aaa	1.90	2.04	2.36
10-year A	3.01	3.13	3.47
25/30-year Aaa	3.30	3.55	3.88
25/30-year A	4.73	4.87	5.53
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.22	4.32	4.56
Electric AA	4.30	4.63	4.92
Housing AA	4.67	4.75	5.55
Hospital AA	4.42	4.57	4.92
Toll Road Aaa	4.23	4.40	4.58

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/19/12	**9/5/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1425100	1450818	-25718	1462603	1471716	1498949
Borrowed Reserves	2007	2516	-509	3670	5115	7331
Net Free/Borrowed Reserves	1423093	1448302	-25209	1458934	1466600	1491618

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/17/12	**9/10/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2385.8	2373.4	12.4	25.8%	15.7%	12.7%
M2 (M1+savings+small time deposits)	10137.9	10124.1	13.8	8.5%	7.2%	7.1%

Source: United States Federal Reserve Bank

ATTACHMENT D

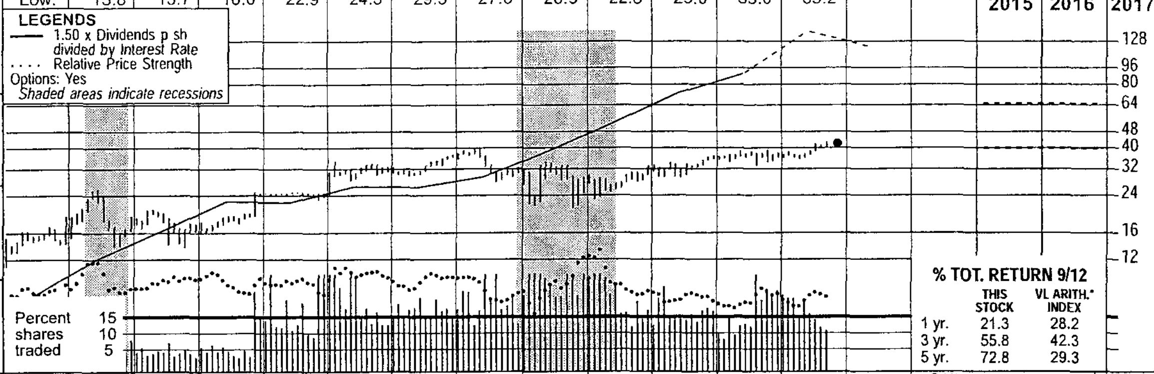
UNS ENERGY NYSE-UNS

RECENT PRICE	42.20	P/E RATIO	17.4 (Trailing: 16.9 / Median: 17.0)	RELATIVE P/E RATIO	1.14	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 3 Lowered 11/11/11
SAFETY 3 New 12/31/04
TECHNICAL 2 Raised 10/26/12
BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	26.0	20.8	24.9	24.9	34.8	37.5	40.0	34.5	33.3	36.9	39.3	43.0
Low:	13.8	13.7	16.0	22.9	24.3	29.5	27.6	20.9	22.8	29.0	33.0	35.2

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+55%)	15%
Low	40	(-5%)	4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	0	4
to Sell	1	0	0	0	0	0	0	0	3

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	87	80	97
to Sell	73	93	78
Hld's(000)	32564	33499	33380

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.3	28.2
3 yr.	55.8	42.3
5 yr.	72.8	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.28	22.71	23.83	24.85	31.12	43.12	25.50	28.71	34.13	35.26	37.42	39.12	39.41	38.89	39.78	40.89	*35.20*	*36.15*	Revenues per sh	*41.55*
6.82	5.29	3.48	3.96	4.23	5.41	4.80	5.20	5.29	5.21	5.68	5.64	4.56	7.82	7.33	7.44	*6.25*	*6.75*	"Cash Flow" per sh	*7.95*
3.76	2.60	.68	1.08	1.27	1.79	.97	1.30	1.31	1.30	1.85	1.55	.39	2.69	2.82	2.75	*2.25*	*2.75*	Earnings per sh A	*3.75*
--	--	--	--	.32	.40	.50	.60	.64	.76	.84	.90	.96	1.16	1.56	1.68	*1.72*	*1.76*	Div'd Decl'd per sh B ■ †	*2.25*
2.07	2.22	2.52	2.87	3.19	3.63	3.36	4.06	4.49	5.83	6.77	6.95	9.85	8.01	7.26	10.13	*7.95*	*9.60*	Cap'l Spending per sh	*11.40*
4.15	6.75	7.65	10.02	11.20	12.68	13.05	15.97	16.95	17.68	18.59	19.54	19.16	20.94	22.46	24.07	*21.95*	*22.90*	Book Value per sh	*27.20*
32.13	32.14	32.26	32.35	33.22	33.50	33.58	33.79	34.26	34.87	35.19	35.32	35.46	35.85	36.54	36.92	*41.50*	*41.50*	Common Shs Outst'g C	*41.00*
4.3	6.1	23.3	10.8	11.8	10.8	18.2	14.6	18.7	23.9	17.7	22.0	73.8	10.4	11.6	13.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.27	.35	1.21	.62	.77	.55	.99	.83	.99	1.27	.96	1.17	4.44	.69	.74	.84	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	2.1%	2.1%	2.8%	3.2%	2.6%	2.5%	2.6%	2.6%	3.3%	4.1%	4.8%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1900.5 mill. Due in 5 Yrs $770.0 mill.
LT Debt $1386.9 mill. LT Interest $75.0 mill.
Incl. $352.7 mill. capitalized leases.
(LT interest earned: 3.4x)

Pension Assets-12/11 $245 mill. Oblig. $319 mill.
Pfd Stock None

Common Stock 41,265,837 shs.
as of 7/18/12
MARKET CAP: $1.7 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
856.2	969.9	1169.0	1229.5	1316.9	1381.4	1397.5	1394.4	1453.7	1509.5	*1460*	*1500*	Revenues ($mill)	*1700*
33.3	45.2	45.9	46.1	69.2	58.4	14.0	104.3	111.5	110.0	*95.0*	*115*	Net Profit ($mill)	*155*
33.7%	19.7%	42.5%	41.4%	38.8%	40.1%	54.8%	38.2%	41.2%	37.8%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
--	2.2%	--	--	2.9%	3.4%	--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
81.5%	79.2%	77.1%	75.3%	72.9%	68.8%	72.9%	70.5%	68.5%	67.8%	*69.0%*	*69.5%*	Long-Term Debt Ratio	*72.0%*
18.5%	20.8%	22.9%	24.7%	27.1%	31.2%	27.1%	29.5%	31.5%	32.2%	*31.0%*	*30.5%*	Common Equity Ratio	*28.0%*
2368.8	2589.0	2540.3	2494.9	2414.1	2214.9	2506.4	2547.0	2602.8	2758.6	*2930*	*3135*	Total Capital ($mill)	*3950*
1668.4	2069.2	2081.1	2171.5	2259.6	2407.3	2617.7	2785.7	2961.5	3182.3	*3405*	*3645*	Net Plant ($mill)	*4465*
2.8%	4.9%	5.1%	5.1%	5.9%	5.7%	3.0%	5.2%	5.5%	5.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
7.6%	8.4%	7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	*10.5%*	*12.0%*	Return on Shr. Equity	*14.0%*
7.6%	8.4%	7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	*10.5%*	*12.0%*	Return on Com Equity D	*14.0%*
3.8%	4.6%	4.1%	3.2%	6.1%	3.9%	NMF	8.4%	6.7%	5.4%	*2.5%*	*4.5%*	Retained to Com Eq	*5.5%*
51%	45%	48%	57%	43%	54%	NMF	40%	51%	56%	*75%*	*64%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.4	-.8	+.4
Avg. Indust. Use (MWH)	5096	5076	5064
Avg. Indust. Revs. per KWH (¢)	7.00	6.90	7.10
Capacity at Peak (Mw)	3010	3044	3271
Peak Load, Summer (Mw)	2354	2333	2334
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.3	+.4
Fixed Charge Cov. (%)	232	268	251

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.0%	2.5%	.5%
"Cash Flow"	5.0%	7.0%	1.0%
Earnings	7.0%	13.0%	5.5%
Dividends	20.0%	14.5%	7.5%
Book Value	7.0%	5.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	311.9	337.8	414.2	330.5	1394.4
2010	317.9	337.8	438.8	359.2	1453.7
2011	344.8	369.7	450.9	344.1	1509.5
2012	318.9	367.2	*435*	*338.9*	*1460*
2013	*340*	*345*	*450*	*365*	*1500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.14	.80	1.45	.30	2.69
2010	.52	.65	1.36	.29	2.82
2011	.35	.71	1.46	.22	2.75
2012	.17	.64	*1.25*	*.19*	*2.25*
2013	*.35*	*.70*	*1.45*	*.25*	*2.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.24	.24	.24	.24	.96
2009	.29	.29	.29	.29	1.16
2010	.39	.39	.39	.39	1.56
2011	.42	.42	.42	.42	1.68
2012	.43	.43	.43		

BUSINESS: UNS Energy Corporation, through its subsidiaries, operates as an electric utility in Arizona. Subsidiaries include Tuscon Electric Power (TEP), UNS Gas, and UNS Electric. TEP segment serves about 404,000 retail customers in southern Arizona and accounted for 77% of '11 net income. Revenue sources: residential, 42%; commercial, 21%; industrial, 34%; other, 3%. Copper mining is largest industry served. Fuels: coal, 92%; gas, 8%. '11 TEP reported depreciation rate: 3.2%. Has 2,004 employees: TEP, 1,391; UNS Gas, 187; UNS Electric, 154; Other, 272. Chrmn. & CEO: Paul J. Bonavia. Pres.: David G. Hutchens. Inc.: AZ. Address: 88 E. Broadway Blvd., Tucson, AZ. 85701. Telephone: 520-571-4000. Internet: www.unisourceenergy.com.

UNS Energy reported mixed second-quarter results. Earnings decreased 10% compared to the prior-year figure, to $0.64 a share. As expected, the bottom line was negatively impacted by UNS Energy's primary subsidiary, Tuscan Electric Power (TEP), and its four-year base-rate freeze, which will end December 1, 2012. On the plus side, earnings were slightly better than expected, as TEP's retail sales were up 4.6% year over year, due to warmer weather.

The process to implement new rates by August 31, 2013 (13 months after its July 2nd filing date) is on track. In August, TEP and the ACC Staff proposed a schedule, indicating that both parties will try to reach a settlement agreement by January, 2013. Recall, TEP filed for $128 million in annual revenue increases, based on its 2011 test year, and is requesting a 10.75% rate of return. Additionally, its Energy Efficiency Resource Plan is in the works, a three-year pilot program, which would allow UNS to get a return on its investments in energy-efficiency programs. The subsidiary is also requesting a lost fixed-cost recover mechanism (LFCR). This would recover nonfuel costs related to energy-efficiency and renewable-energy regulations, which were not accounted for in its 2008 settlement agreement.

Although these rate increases are anticipated to drive earnings in 2013, our short-term outlook remains weak. TEP's inability to file for rate increases since 2008 has hindered the bottom line, as its rates are based on costs and investments from 2006. We think share earnings for 2012 will contract approximately 18% from the year-ago tally, to $2.25. That said, the new rates should boost earnings in 2013, to $2.75 share. Overall, the base-rate hike is intended to promote long-term financial stability, provide an appropriate rate of return, and allow for further investment in its energy-efficiency and renewable-energy initiatives.

UNS Energy's dividend yield of 4.1% is in line with the utility average. Indeed, the company has increased its dividend annually since 2000, and we expect these raises to continue going forward. All told, this issue may interest income-seeking investors.

Michelle Jensen *November 2, 2012*

(A) EPS diluted. Excl. nonrecur. gains (losses): '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. Next earnings report due late Feb. Earnings may not sum due to rounding. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) In millions. (D) Rate base: fair value. Rate allowed on com. eq. in '08: 10.25%; earned on avg. com. eq., '11: 12.4%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	35

ZACKS INVESTMENT RESEARCH
Proven Ratings, Research & Recommendations
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UNS ENERGY CORP (NYSE)

ZACKS RANK: 4 - SELL

UNS 40.25 ▲0.16 (0.40%) Vol. 122,489 15:08 ET

UNS Energy Corporation is a utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. It operates in three segments: TEP, UNS Gas and UNS Electric. Its TEP segment generates, transmits, and distributes electricity to retail electric customers in southeastern Arizona. This segment also sells electricity to other utilities and power marketing entities. UNS Gas segment distributes gas to retail customers particularly in Mohave, Yavapai, Coconino and Navajo counties in northern Arizona and Santa Cruz County in southeastern Arizona. Its UNS Electric segment transmits and distributes electricity to retail customers in Mohave and Santa Cruz counties. UNS Energy Corporation, formerly known as UniSource Energy Corporation, is headquartered in Tucson, Arizona.

General Information

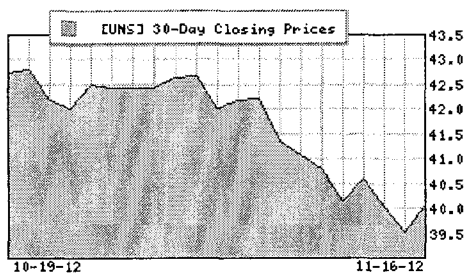
UNS ENERGY CORP
88 EAST BROADWAY
TUCSON, AZ 85701
Phone: 520-571-4000
Fax: 5207702089
Web: http://www.uns.com/
Email: cnorman@uns.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/12
Next EPS Date	03/04/2013

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.09
52 Week High	43.12
52 Week Low	34.62
Beta	0.64
20 Day Moving Average	143,152.66
Target Price Consensus	44



% Price Change	
4 Week	-6.20
12 Week	0.07
YTD	8.59

% Price Change Relative to S&P 500	
4 Week	-1.14
12 Week	3.85
YTD	0.42

Share Information	
Shares Outstanding (millions)	41.27
Market Capitalization (millions)	1,654.35
Short Ratio	6.25
Last Split Date	05/20/1996

Dividend Information	
Dividend Yield	4.29%
Annual Dividend	$1.72
Payout Ratio	0.76
Change in Payout Ratio	0.59
Last Dividend Payout / Amount	08/31/2012 / $0.43

EPS Information	
Current Quarter EPS Consensus Estimate	0.17
Current Year EPS Consensus Estimate	2.20
Estimated Long-Term EPS Growth Rate	6.30
Next EPS Report Date	03/04/2013

Consensus Recommendations	
Current (1=Strong Buy, 5=Strong Sell)	2.00
30 Days Ago	2.00
60 Days Ago	2.00
90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.22	vs. Previous Year	-8.82%	vs. Previous Year	-3.03%
Trailing 12 Months:	17.66	vs. Previous Quarter	93.75%	vs. Previous Quarter:	19.09%

PEG Ratio 2.89

Price Ratios		**ROE**		**ROA**	
Price/Book	1.54	09/30/12	9.37	09/30/12	2.29
Price/Cash Flow	5.34	06/30/12	10.24	06/30/12	2.43
Price / Sales	1.13	03/31/12	11.05	03/31/12	2.52
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/12	1.59	09/30/12	1.21	09/30/12	6.32
06/30/12	1.06	06/30/12	0.80	06/30/12	6.53
03/31/12	1.04	03/31/12	0.78	03/31/12	6.67
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/12	10.02	09/30/12	10.02	09/30/12	26.07
06/30/12	11.01	06/30/12	11.01	06/30/12	25.79
03/31/12	11.17	03/31/12	11.17	03/31/12	25.13
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/12	7.24	09/30/12	1.65	09/30/12	62.29
06/30/12	8.24	06/30/12	1.60	06/30/12	61.56
03/31/12	9.15	03/31/12	1.80	03/31/12	64.35

TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291
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SCHEDULE #	
WAR - 1	COST OF CAPITAL SUMMARY
WAR - 2	DCF COST OF EQUITY CAPITAL
WAR - 3	DIVIDEND YIELD CALCULATION
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TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
COST OF CAPITAL SUMMARY

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ 10,000	$ -	$ 10,000	0.53%	1.42%	0.01%
2	LONG-TERM DEBT	1,061,389	-	1,061,389	55.97%	5.22%	2.92%
3	COMMON EQUITY	824,983	-	824,983	43.50%	10.00%	4.35%
4	TOTAL CAPITALIZATION	$ 1,896,372	$ -	$ 1,896,372	100.00%		
5	ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL						7.28%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) + COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - SCHEDULE WAR-1, PAGE 2 LINE 17
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 3 LINE 7
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E)	(F) WEIGHTED
1	SHORT-TERM DEBT	$ 10,000	$ -	$ 10,000	0.53%	1.42%	0.01%
2	LONG-TERM DEBT	1,061,389	-	1,061,389	55.97%	3.03%	1.70%
3	COMMON EQUITY	824,983	-	824,983	43.50%	7.81%	3.40%
4	TOTAL CAPITALIZATION	$ 1,896,372	$ -	$ 1,896,372	100.00%		
5	FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL						5.11%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) + COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - SCHEDULE WAR-1, PAGE 2 LINE 19
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 3 LINE 9
COLUMN (F): COLUMN (D) x COLUMN (E)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
COST OF CAPITAL SUMMARY

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 1
PAGE 2 OF 4

COST OF LONG-TERM DEBT (000'S)

LINE NO.	DESCRIPTION	(A) BALANCE AS OF DECEMBER 31, 2011	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED BALANCE	(D) ANNUAL INTEREST	(E) COST RATE
	FIXED RATE TAXABLE BONDS:					
1	5.150% SERIES DUE 2021	$ 250,000	$ -	$ 250,000	$ 12,875	
2	TOTAL FIXED RATE TAXABLE BONDS (SUM OF LINE 1)	250,000	-	250,000	12,875	5.15%
	FIXED RATE TAX-EXEMPT BONDS:					
3	5.850% 1998 APACHE A	83,700	-	83,700	4,897	
4	5.875% 1998 APACHE B	99,800	-	99,800	5,863	
5	5.850% 1998 APACHE C	16,500	-	16,500	965	
6	6.375% 2008 PIMA A	90,745	-	90,745	5,785	
7	5.750% 2008 PIMA B	130,000	-	130,000	7,475	
8	4.950% 2009 PIMA A (San Juan)	80,410	-	80,410	3,980	
9	5.125% 2009 COCONINO A	14,700	-	14,700	753	
10	5.250% 2010 PIMA A	100,000	-	100,000	5,250	
11	TOTAL FIXED RATE TAX-EXEMPT BONDS (SUM OF LINES 3 THROUGH 10)	615,855	-	615,855	34,968	5.68%
	VARIABLE RATE TAX-EXEMPT BONDS:					
12	VARIABLE 1982 PIMA A IRVINGTON	38,700	-	38,700	632	
13	VARIABLE 1982 PIMA A IRVINGTON & FOUR CORNERS	39,900	-	39,900	649	
14	VARIABLE 2010 COCONINO A	100,000	-	100,000	2,799	
15	VARIABLE 1982 PIMA A IRVINGTON	36,700	-	36,700	689	
16	TOTAL VARIABLE RATE TAX-EXEMPT BONDS (SUM OF LINES 12 THROUGH 15)	215,300	-	215,300	4,769	2.22%
17	TOTAL LONG-TERM DEBT (SUM OF LINES 2,11 AND 16)	1,081,155	-	1,081,155	52,612	4.87%
18	UNAMORTIZED DEBT DISCOUNT, PREMIUM AND EXPENSE AND LOSS ON REAQUIRED DEBT	(19,766)	-	(19,766)		
19	AMORTIZATION OF DEBT DISCOUNT AND EXPENSE AND LOSS ON REAQUIRED DEBT				2,378	
20	CREDIT FACILITY COMMITMENT FEES				395	
21	TOTAL LONG-TERM DEBT - NET (SUM OF LINES 17, 18, 19 AND 20)	1,061,389	-	1,061,389	55,385	5.22%
22	**COST OF LONG-TERM DEBT - ORIGINAL COST (COLUMN (E), LINE 21)**					**5.22%**
23	**LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT (SCHEDULE WAR 1, PAGE 4, LINE 11)**					**2.19%**
24	**COST OF LONG-TERM DEBT - FAIR VALUE (LINE 22 - LINE 23)**					**3.03%**

REFERENCES:
COLUMNS (A): COMPANY SCHEDULE D-2, PAGE 1 OF 2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMNS (D): COMPANY SCHEDULE D-2, PAGE 1 OF 2
COLUMN (E): COLUMN (D), LINES 2, 11, 16, 17 AND 21 / COLUMN (C) LINES 2, 11, 16, 17 AND 21

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.60%	SCHEDULE WAR-2, COLUMN (C), LINE 10
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	5.82%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 10
5	CAPM - ARITHMETIC MEAN ESTIMATE	6.98%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 10
6	AVERAGE OF CAPM ESTIMATES	6.40%	(LINE 4 + LINE 5) / 2
7	**COST OF COMMON EQUITY ESTIMATE - ORIGINAL COST**	**10.00%**	TESTIMONY, WAR
8	**LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**	**2.19%**	SCHEDULE WAR-1, PAGE 4, COLUMN (D), LINE 11
9	**COST OF COMMON EQUITY ESTIMATE - FAIR VALUE**	$\boxed{7.81\%}$	LINE 8 - LINE 9

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
COST OF CAPITAL SUMMARY

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2004	1.83%	4.27%	2.44%
2	2005	1.81%	4.29%	2.48%
3	2006	2.31%	4.54%	2.23%
4	2007	2.29%	4.63%	2.34%
5	2008	1.77%	3.66%	1.89%
6	2009	1.66%	3.26%	1.60%
7	2010	1.15%	3.22%	2.07%
8	2011	0.55%	2.78%	2.23%
9	2012	-0.45%	1.99%	2.44%
10	AVERAGE	1.44%	3.63%	2.19%
11	**RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**			**2.19%**

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK OF ST. LOUIS WEBSITE
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 9
COLUMN (D), LINE 11: TESTIMONY - WAR

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) DIVIDEND YIELD		(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.40%	+	3.92%	=	8.32%
2	CNL	CLECO CORPORATION	3.30%	+	5.45%	=	8.75%
3	EDE	EMPIRE DISTRICT ELECTRIC	4.84%	+	3.07%	=	7.91%
4	ETR	ENTERGY CORPORATION	4.97%	+	3.55%	=	8.52%
5	GXP	GREAT PLAINS ENERGY, INC.	4.01%	+	20.69%	=	24.71%
6	HE	HAWAIIAN ELECTRIC	4.93%	+	4.29%	=	9.23%
7	IDA	IDACORP, INC.	3.54%	+	5.37%	=	8.91%
8	NVE	NV ENERGY, INC.	3.71%	+	4.00%	=	7.71%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	4.25%	+	4.15%	=	8.40%
10	PNM	PNM RESOURCES, INC.	2.74%	+	4.63%	=	7.38%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.04%	+	4.03%	=	8.07%
12	SO	SOUTHERN COMPANY	4.43%	+	4.54%	=	8.97%
13	WR	WESTAR ENERGY	4.56%	+	3.40%	=	7.96%
14	**AVERAGE**						**9.60%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	$ 1.88	/	$ 42.77	=	4.40%
2	CNL	CLECO CORPORATION	1.35	/	40.87	=	3.30%
3	EDE	EMPIRE DISTRICT ELECTRIC	1.00	/	20.67	=	4.84%
4	ETR	ENTERGY CORPORATION	3.32	/	66.75	=	4.97%
5	GXP	GREAT PLAINS ENERGY, INC.	0.85	/	21.19	=	4.01%
6	HE	HAWAIIAN ELECTRIC	1.24	/	25.13	=	4.93%
7	IDA	IDACORP, INC.	1.52	/	42.95	=	3.54%
8	NVE	NV ENERGY, INC.	0.68	/	18.33	=	3.71%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	2.18	/	51.28	=	4.25%
10	PNM	PNM RESOURCES, INC.	0.58	/	21.13	=	2.74%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	1.08	/	26.72	=	4.04%
12	SO	SOUTHERN COMPANY	1.96	/	44.26	=	4.43%
13	WR	WESTAR ENERGY	1.32	/	28.93	=	4.56%
14	**AVERAGE**						**4.13%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	3.80%	+	0.12%	=	3.92%
2	CNL	CLECO CORPORATION	5.20%	+	0.25%	=	5.45%
3	EDE	EMPIRE DISTRICT ELECTRIC	3.00%	+	0.07%	=	3.07%
4	ETR	ENTERGY CORPORATION	3.50%	+	0.05%	=	3.55%
5	GXP	GREAT PLAINS ENERGY, INC.	2.80%	+	17.89%	=	20.69%
6	HE	HAWAIIAN ELECTRIC	3.00%	+	1.29%	=	4.29%
7	IDA	IDACORP, INC.	5.25%	+	0.12%	=	5.37%
8	NVE	NV ENERGY, INC.	4.00%	+	0.00%	=	4.00%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	3.80%	+	0.35%	=	4.15%
10	PNM	PNM RESOURCES, INC.	4.60%	+	0.03%	=	4.63%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.00%	+	0.03%	=	4.03%
12	SO	SOUTHERN COMPANY	3.90%	+	0.64%	=	4.54%
13	WR	WESTAR ENERGY	3.25%	+	0.15%	=	3.40%
14	**AVERAGE**						**5.47%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) SHARE GROWTH		(B) [((M ÷ B) + 1) ÷ 2] - 1	=	(C) EXTERNAL GROWTH (sv)
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	0.70%	x	{ [((1.35) + 1) ÷ 2] - 1 }	=	0.12%
2	CNL	CLECO CORPORATION	0.75%	x	{ [((1.66) + 1) ÷ 2] - 1 }	=	0.25%
3	EDE	EMPIRE DISTRICT ELECTRIC	0.60%	x	{ [((1.23) + 1) ÷ 2] - 1 }	=	0.07%
4	ETR	ENTERGY CORPORATION	0.30%	x	{ [((1.30) + 1) ÷ 2] - 1 }	=	0.05%
5	GXP	GREAT PLAINS ENERGY, INC.	9.00%	x	{ [((0.98) + 1) ÷ 2] + 1 }	=	17.89%
6	HE	HAWAIIAN ELECTRIC	4.90%	x	{ [((1.53) + 1) ÷ 2] - 1 }	=	1.29%
7	IDA	IDACORP, INC.	1.10%	x	{ [((1.22) + 1) ÷ 2] - 1 }	=	0.12%
8	NVE	NV ENERGY, INC.	0.01%	x	{ [((1.22) + 1) ÷ 2] - 1 }	=	0.00%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	1.70%	x	{ [((1.41) + 1) ÷ 2] - 1 }	=	0.35%
10	PNM	PNM RESOURCES, INC.	1.30%	x	{ [((1.05) + 1) ÷ 2] - 1 }	=	0.03%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	0.30%	x	{ [((1.17) + 1) ÷ 2] - 1 }	=	0.03%
12	SO	SOUTHERN COMPANY	1.15%	x	{ [((2.11) + 1) ÷ 2] - 1 }	=	0.64%
13	WR	WESTAR ENERGY	1.30%	x	{ [((1.23) + 1) ÷ 2] - 1 }	=	0.15%
14	**AVERAGE**						**1.61%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (C): COLUMN (A) x COLUMN (B)

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	2007	0.4476	11.40%	5.10%	25.17	400.43	
2			2008	0.4515	11.30%	5.10%	26.33	406.07	
3			2009	0.4478	10.40%	4.66%	27.49	478.05	
4			2010	0.3423	9.10%	3.12%	28.33	480.81	
5			2011	0.4089	10.30%	4.21%	30.33	483.42	
6			GROWTH 2007 - 2011			4.27%	5.00%		4.82%
7			2012	0.3871	10.00%	3.87%		486.00	0.53%
8			2013	0.3677	9.50%	3.49%		489.00	0.58%
9			2015-17	0.3857	9.50%	3.66%	4.00%	500.00	0.68%
10									
11	CNL	CLECO CORPORATION	2007	0.3182	7.80%	2.48%	16.85	59.94	
12			2008	0.4706	9.60%	4.52%	17.65	60.04	
13			2009	0.4886	9.50%	4.64%	18.50	60.26	
14			2010	0.5721	10.60%	6.06%	21.76	60.53	
15			2011	0.5676	11.10%	6.30%	23.55	60.29	
16			GROWTH 2007 - 2011			4.49%	10.00%		0.15%
17			2012	0.5000	10.50%	5.25%		61.00	1.18%
18			2013	0.4510	10.00%	4.51%		61.00	0.59%
19			2015-17	0.4154	11.50%	4.78%	6.00%	61.00	0.23%
20									
21	EDE	EMPIRE DISTRICT ELECTRIC	2007	-0.1743	6.20%	NMF	16.04	33.61	
22			2008	-0.0940	7.50%	NMF	15.56	33.98	
23			2009	-0.0847	6.90%	NMF	15.75	38.11	
24			2010	-0.0940	7.20%	NMF	15.82	41.58	
25			2011	0.5115	7.90%	4.04%	16.53	41.98	
26			GROWTH 2007 - 2011			4.04%	1.00%		5.72%
27			2012	0.2000	7.50%	1.50%		42.25	0.64%
28			2013	0.2857	8.00%	2.29%		42.50	0.62%
29			2015-17	0.3143	9.00%	2.83%	2.50%	43.25	0.60%
30									
31	ETR	ENTERGY CORPORATION	2007	0.5393	14.40%	7.77%	40.71	193.12	
32			2008	0.5161	15.30%	7.90%	42.07	189.36	
33			2009	0.5238	14.30%	7.49%	45.54	189.12	
34			2010	0.5135	14.70%	7.55%	47.53	178.75	
35			2011	0.5603	15.00%	8.40%	50.81	176.36	
36			GROWTH 2007 - 2011			7.82%	4.50%		-2.24%
37			2012	0.3615	10.00%	3.62%		177.00	0.36%
38			2013	0.2539	9.00%	2.29%		171.00	-1.53%
39			2015-17	0.3200	9.00%	2.88%	3.00%	171.00	-0.62%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	GXP	GREAT PLAINS ENERGY, INC.	2007	0.1075		10.10%		1.09%	18.18	86.23	
2			2008	-0.4310		4.60%		NMF	21.39	119.26	
3			2009	0.1942		4.80%		0.93%	20.62	135.42	
4			2010	0.4575		7.30%		3.34%	21.26	135.71	
5			2011	0.3280		5.80%		1.90%	21.74	136.14	
6			GROWTH 2007 - 2011					1.82%	5.50%		12.09%
7			2012	0.3630		6.00%		2.18%		153.50	12.75%
8			2013	0.3714		6.50%		2.41%		153.50	6.18%
9			2015-17	0.3714		7.50%		2.79%	2.00%	153.50	2.43%
10											
11	HE	HAWAIIAN ELECTRIC	2007	-0.1171		7.20%		NMF	15.29	83.43	
12			2008	-0.1589		6.50%		NMF	15.35	90.52	
13			2009	-0.3626		5.80%		NMF	15.58	92.52	
14			2010	-0.0248		7.70%		NMF	15.67	94.69	
15			2011	0.1389		9.00%		1.25%	15.95	96.04	
16			GROWTH 2007 - 2011					1.25%	1.50%		3.58%
17			2012	0.2250		10.00%		2.25%		98.00	2.04%
18			2013	0.2706		9.50%		2.57%		104.00	4.06%
19			2015-17	0.3000		10.00%		3.00%	4.50%	122.00	4.90%
20											
21	IDA	IDACORP, INC.	2007	0.3548		6.80%		2.41%	26.79	45.06	
22			2008	0.4495		7.60%		3.42%	27.76	46.92	
23			2009	0.5455		8.90%		4.85%	29.17	47.90	
24			2010	0.5932		9.30%		5.52%	31.01	49.41	
25			2011	0.6429		10.10%		6.49%	33.19	49.95	
26			GROWTH 2007 - 2011					4.54%	5.00%		2.61%
27			2012	0.5848		9.50%		5.56%		50.00	0.10%
28			2013	0.5323		8.50%		4.52%		50.00	0.05%
29			2015-17	0.4412		8.50%		3.75%	4.00%	53.00	1.19%
30											
31	NVE	NV ENERGY, INC.	2007	0.8202		6.60%		5.41%	12.82	233.74	
32			2008	0.6180		6.70%		4.14%	13.36	234.32	
33			2009	0.4744		5.70%		2.70%	13.73	234.83	
34			2010	0.5313		6.80%		3.61%	14.24	235.32	
35			2011	0.2899		4.80%		1.39%	14.43	236.00	
36			GROWTH 2007 - 2011					3.45%	4.00%		0.24%
37			2012	0.4880		8.50%		4.15%		236.00	0.00%
38			2013	0.4080		8.00%		3.26%		236.00	0.00%
39			2015-17	0.3333		9.00%		3.00%	3.50%	236.00	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PNW	PINNACLE WEST CAPITAL CORPORATION	2007	0.2905		8.50%		2.47%	35.15	100.49	
2			2008	0.0094		6.20%		0.06%	34.16	100.89	
3			2009	0.0708		6.90%		0.49%	32.69	101.43	
4			2010	0.3182		9.00%		2.86%	33.86	108.77	
5			2011	0.2977		8.60%		2.56%	34.98	109.25	
6			GROWTH 2007 - 2011					1.69%	-		2.11%
7			2012	0.3855		9.50%		3.66%		110.00	0.69%
8			2013	0.3714		9.50%		3.53%		111.00	0.80%
9			2015-17	0.3467		9.00%		3.12%	35.00%	118.50	1.64%
10											
11	PNM	PNM RESOURCES, INC.	2007	-0.1974		3.50%		NMF	22.03	76.81	
12			2008	-4.5455		0.50%		NMF	18.89	86.53	
13			2009	0.1379		3.20%		0.44%	18.90	86.67	
14			2010	0.4253		5.20%		2.21%	17.60	86.67	
15			2011	0.5370		6.10%		3.28%	19.62	79.65	
16			GROWTH 2007 - 2011					1.98%	-1.00%		0.91%
17			2012	0.5538		6.00%		3.32%		80.00	0.44%
18			2013	0.5000		7.00%		3.50%		80.00	0.22%
19			2015-17	0.5122		9.00%		4.61%	3.00%	85.00	1.31%
20											
21	POR	PORTLAND GENERAL ELECTRIC COMPANY	2007	0.6009		11.00%		6.61%	21.05	62.53	
22			2008	0.3022		6.40%		1.93%	21.64	62.58	
23			2009	0.2290		6.20%		1.42%	20.50	75.21	
24			2010	0.3735		7.90%		2.95%	21.14	75.32	
25			2011	0.4564		8.80%		4.02%	22.07	75.36	
26			GROWTH 2007 - 2011					3.39%	2.00%		4.78%
27			2012	0.4316		8.00%		3.45%		75.55	0.25%
28			2013	0.4308		8.00%		3.45%		75.75	0.26%
29			2015-17	0.4444		9.00%		4.00%	3.50%	76.50	0.30%
30											
31	SO	SOUTHERN COMPANY	2007	0.2982		14.00%		4.18%	16.23	763.10	
32			2008	0.2622		13.10%		3.44%	17.08	777.19	
33			2009	0.2543		12.40%		3.15%	18.15	819.65	
34			2010	0.2373		12.20%		2.89%	19.21	843.34	
35			2011	0.2667		12.50%		3.33%	20.32	865.13	
36			GROWTH 2007 - 2011					3.40%	6.00%		3.19%
37			2012	0.2679		12.50%		3.35%		868.00	0.33%
38			2013	0.2786		13.00%		3.62%		870.00	0.28%
39			2015-17	0.3077		12.50%		3.85%	5.00%	915.00	1.13%

REFERENCES:

COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	WR	WESTAR ENERGY	2007	0.4130		9.20%		3.80%	19.14	95.46	
2			2008	0.1145		6.20%		0.71%	20.18	108.31	
3			2009	0.0625		6.30%		0.39%	20.59	109.07	
4			2010	0.3111		8.50%		2.64%	21.25	112.13	
5			2011	0.2849		7.70%		2.19%	22.20	125.70	
6			GROWTH 2007 - 2011					1.95%	6.00%		7.12%
7			2012	0.3231		8.50%		2.75%		127.00	1.03%
8			2013	0.3366		8.00%		2.69%		128.00	0.91%
9			2015-17	0.3833		8.50%		3.26%	5.00%	134.00	1.29%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2007 - 2011

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
GROWTH RATE COMPARISON

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	DPS	BVPS	(D) VALUE LINE HISTORIC EPS	DPS	BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	DPS	BVPS
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	3.92%	3.50%	3.00%	3.50%	4.00%	1.50%	4.00%	5.00%	3.50%	2.28%	4.02%	4.77%
2	CNL	CLECO CORPORATION	5.45%	3.00%	6.50%	11.50%	6.00%	10.00%	2.00%	10.00%	7.00%	18.35%	5.62%	8.73%
3	EDE	EMPIRE DISTRICT ELECTRIC	3.07%	-	6.00%	2.00%	2.50%	3.00%	-3.50%	1.00%	1.83%	4.70%	-15.91%	0.76%
4	ETR	ENTERGY CORPORATION	3.55%	-1.50%	-5.00%	1.00%	3.00%	8.50%	9.00%	4.50%	2.79%	7.76%	6.51%	5.70%
5	GXP	GREAT PLAINS ENERGY, INC.	20.69%	8.20%	5.50%	5.00%	2.00%	-9.50%	-13.00%	5.50%	0.53%	-9.46%	-15.66%	4.57%
6	HE	HAWAIIAN ELECTRIC	4.29%	7.00%	9.00%	2.00%	4.50%	-3.00%	-	1.50%	3.50%	6.72%	0.00%	1.06%
7	IDA	IDACORP, INC.	5.37%	4.00%	2.00%	8.00%	4.00%	8.50%	-	5.00%	5.25%	15.93%	0.00%	5.50%
8	NVE	NV ENERGY, INC.	4.00%	15.10%	11.00%	14.00%	3.50%	4.00%	-	4.00%	8.60%	-6.17%	32.29%	3.00%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	4.15%	6.00%	5.00%	2.50%	35.00%	1.00%	1.50%	-	8.50%	0.25%	0.00%	-0.12%
10	PNM	PNM RESOURCES, INC.	4.63%	8.20%	16.00%	12.00%	3.00%	-12.00%	-8.00%	-1.00%	2.60%	9.18%	-13.90%	-2.85%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.03%	4.10%	5.50%	3.50%	3.50%	8.50%	NMF	2.00%	4.52%	-4.35%	3.33%	1.19%
12	SO	SOUTHERN COMPANY	4.54%	5.20%	5.00%	4.00%	5.00%	3.00%	4.00%	6.00%	4.60%	2.84%	3.98%	5.78%
13	WR	WESTAR ENERGY	3.40%	5.70%	6.50%	3.00%	5.00%	1.00%	7.00%	6.00%	4.89%	-0.69%	4.34%	3.78%
14					5.85%	5.54%	6.23%	1.88%	0.33%	4.13%		3.64%	1.12%	3.22%
15	AVERAGES		5.47%	5.71%		5.87%			2.11%		4.47%		2.66%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/21/2012, 11/02/2012 AND 11/23/2012
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THROUGH 20
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 09/21/2012, 11/02/2012 AND 11/23/2012

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
CAPM COST OF EQUITY CAPITAL

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 7
PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f (A)	+ [	ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
2	CNL	CLECO CORPORATION	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
3	EDE	EMPIRE DISTRICT ELECTRIC	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
4	ETR	ENTERGY CORPORATION	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
5	GXP	GREAT PLAINS ENERGY, INC.	k	=	2.86%	+ [	0.75	x (	9.80%	-	5.70%	)]	=	5.93%
6	HE	HAWAIIAN ELECTRIC	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
7	IDA	IDACORP, INC.	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
8	NVE	NV ENERGY, INC.	k	=	2.86%	+ [	0.85	x (	9.80%	-	5.70%	)]	=	6.34%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
10	PNM	PNM RESOURCES, INC.	k	=	2.86%	+ [	0.95	x (	9.80%	-	5.70%	)]	=	6.75%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	k	=	2.86%	+ [	0.75	x (	9.80%	-	5.70%	)]	=	5.93%
12	SO	SOUTHERN COMPANY	k	=	2.86%	+ [	0.55	x (	9.80%	-	5.70%	)]	=	5.11%
13	WR	WESTAR ENERGY	k	=	2.86%	+ [	0.75	x (	9.80%	-	5.70%	)]	=	5.93%
14	**AVERAGE**						$\boxed{0.72}$							$\boxed{5.82\%}$

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 30-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 10/12/2012 THROUGH 11/30/2012 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2011 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2012 YEARBOOK.

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
CAPM COST OF EQUITY CAPITAL

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) $k = r_f + [\,ß \times (r_m - r_f)\,] =$	(B) EXPECTED RETURN
1	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k = 2.86% + [0.70 x (11.80% - 6.10%)] =	6.85%
2	CNL	CLECO CORPORATION	k = 2.86% + [0.65 x (11.80% - 6.10%)] =	6.56%
3	EDE	EMPIRE DISTRICT ELECTRIC	k = 2.86% + [0.65 x (11.80% - 6.10%)] =	6.56%
4	ETR	ENTERGY CORPORATION	k = 2.86% + [0.70 x (11.80% - 6.10%)] =	6.85%
5	GXP	GREAT PLAINS ENERGY, INC.	k = 2.86% + [0.75 x (11.80% - 6.10%)] =	7.13%
6	HE	HAWAIIAN ELECTRIC	k = 2.86% + [0.70 x (11.80% - 6.10%)] =	6.85%
7	IDA	IDACORP, INC.	k = 2.86% + [0.70 x (11.80% - 6.10%)] =	6.85%
8	NVE	NV ENERGY, INC.	k = 2.86% + [0.85 x (11.80% - 6.10%)] =	7.70%
9	PNW	PINNACLE WEST CAPITAL CORPORATION	k = 2.86% + [0.70 x (11.80% - 6.10%)] =	6.85%
10	PNM	PNM RESOURCES, INC.	k = 2.86% + [0.95 x (11.80% - 6.10%)] =	8.27%
11	POR	PORTLAND GENERAL ELECTRIC COMPANY	k = 2.86% + [0.75 x (11.80% - 6.10%)] =	7.13%
12	SO	SOUTHERN COMPANY	k = 2.86% + [0.55 x (11.80% - 6.10%)] =	5.99%
13	WR	WESTAR ENERGY	k = 2.86% + [0.75 x (11.80% - 6.10%)] =	7.13%
14	**AVERAGE**		0.72	**6.98%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\,ß\,(r_m - r_f)\,]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 30-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 10/12/2012 THROUGH 11/30/2012 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2011 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2012 YEARBOOK.

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	2011	3.00%	1.70%	3.25%	0.75%	0.00-0.25%	0.05%	3.93%	5.06%	5.58%
23	CURRENT	1.80%	2.70%	3.25%	0.75%	0.00% - 0.25%	0.09%	2.82%	3.78%	4.13%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/30/2012
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/30/2012
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
CAPITAL STRUCTURES OF SAMPLE COMPANIES (000's)

DOCKET NO. E-01933A-12-0291
SCHEDULE WAR - 9

LINE NO.											
		AEP	PCT.	CNL	PCT.	EDE	PCT.	ETR	PCT.	GXP	PCT.
1	DEBT	$ 18,166.0	55.3%	$ 1,327.0	51.9%	$ 692.0	49.9%	$ 12,237.0	57.5%	$ 2,742.3	47.8%
2											
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	94.0	0.4%	39.0	0.7%
4											
5	COMMON EQUITY	14,665.0	44.7%	1,231.0	48.1%	694.0	50.1%	8,961.0	42.1%	2,959.9	51.6%
6											
7	TOTALS	$ 32,831.0	100%	$ 2,558.0	100%	$ 1,386.0	100%	$ 21,292.0	100%	$ 5,741.2	100%
8											
9											
10		HE	PCT.	IDA	PCT.	NVE	PCT.	PNW	PCT.	PNM	PCT.
11											
12	DEBT	$ 1,340.0	46.1%	$ 1,387.5	45.5%	$ 3,320.0	53.8%	$ 3,019.0	43.4%	$ 1,672.0	24.3%
13											
14	PREFERRED STOCK	34.0	1.2%	0.0	0.0%	0.0	0.0%	0.0	0.0%	11.5	0.2%
15											
16	COMMON EQUITY	1,531.9	52.7%	1,662.0	54.5%	2,849.0	46.2%	3,931.0	56.6%	5,205.0	75.6%
17											
18	TOTALS	$ 2,905.9	100%	$ 3,049.5	100%	$ 6,169.0	100%	$ 6,950.0	100%	$ 6,888.5	100%
19											
20										ELECTRIC COMPANY SAMPLE	
21		POR	PCT.	SO	PCT.	WR	PCT.			AVERAGE	PCT.
22											
23	DEBT	$ 1,635.0	49.5%	$ 18,647.0	50.5%	$ 2,740.3	49.5%			$ 68,925.1	50.9%
24											
25	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%			179	0.1%
26											
27	COMMON EQUITY	1,666.0	50.5%	18,285.0	49.5%	2,790.6	50.5%			66,431	49.0%
28											
29	TOTALS	$ 3,301.0	100%	$ 36,932.0	100%	$ 5,530.9	100%			$ 135,535.0	100%

REFERENCE:
MOST RECENT SEC 10(k) FILINGS OR COMPANY ANNUAL REPORTS

ORIGINAL

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EXHIBIT
SEIA-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP CHAIRMAN	GARY PIERCE COMMISSIONER	BRENDA BURNS COMMISSIONER
SUSAN BITTER SMITH COMMISSIONER	BOB BURNS COMMISSIONER	

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	**DOCKET NO. E-01933A-12-0291** **NOTICE OF DIRECT TESTIMONY OF CARRIE CULLEN HITT**

Pursuant to the Administrative Law Judge's Procedural Order (p. 3) dated September 6, 2012, Solar Energy Industries Association ("SEIA"), by and through undersigned counsel, hereby provides notice of its filing of the attached Direct Testimony of Carrie Cullen Hitt in this docket.

Respectfully submitted this 11th day of January, 2013.

Court S. Rich
Rose Law Group pc
Attorney for Solar Energy Industries Association

Arizona Corporation Commission
DOCKETED
JAN 11 2013
DOCKETED BY TJM

Original and 13 copies filed on this 11th day of January, 2013 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

I hereby certify that I have this day served the foregoing documents on all parties of record in this proceeding by sending a copy by regular U.S. mail to:

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January 11, 2013

Q. Please state your name and business address.

Carrie Cullen Hitt
PO Box 534
North Scituate MA 02060

Q. Please describe your professional experience and qualifications.

A. My experience and qualifications are described in my curriculum vitae, which is Attachment CCH-1 to this testimony. With respect to the matters to be decided in this case, I have extensive experience. As the former Vice President for Regulatory Affairs at Constellation, now a subsidiary of Exelon, I was involved in or oversaw participation in numerous cases throughout the US related to utility retail rates and cost recovery. In addition, I am familiar with policies and industry frameworks that set the framework for adequate development of renewable resources. With respect to solar issues, I am generally familiar with technical and economic characteristics of the solar PV industry. In addition, I have provided expert witness testimony before several state public utility commissions.

Q. Please describe your educational background.

A. I earned a Bachelor of Art's degree from Clark University and a Masters of Arts from Johns Hopkins School of Advanced International Studies.

Q. On whose behalf are you submitting this testimony?

A. I am submitting testimony on behalf of the Solar Energy Industries Association (SEIA).

Q. Please describe SEIA.

A. SEIA is the national trade association of the United States solar industry, encompassing all solar technologies, including photovoltaics (PV), concentrating solar power, solar heating and cooling, and other technologies. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy.

SEIA's membership includes many companies with offices and facilities in Arizona. Solar generation in Arizona is ranked 3rd in the United States, producing 276 MW of installed solar power in 2011 and 838 cumulative MW to date.[1] In addition, solar companies boast approximately 21,900 total solar PV installations in state.[2]

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[1] SEIA/GTM Solar Market Insight Report Q2 2012; Massachusetts CEC, available at http://www.seia.org/research-resources/solar-market-insight-report-2012-q2.
[2] *Id.*

Q. What is the purpose of your testimony?

A. To respond to the Company's proposal to modify the Large General Service (LGS-13) Rate Schedule, Large General Service (LGS-85N) TOU Rate Schedule, and Large Light & Power (LLP-90N) TOU Rate Schedule and the Proposed Lost Fixed Cost Recovery Mechanism (LFCR).

Q. Please summarize your testimony.

TEP is proposing significant changes to certain commercial rate plans. These changes severely impact existing solar customers, such as schools and businesses, who have already invested in solar energy. The tariff changes will stifle future solar developments by making it very difficult to attract financing for distributed solar energy in Arizona and jeopardizing the confidence of potential future customers seeking to invest in solar energy. In essence, the rate changes make solar energy less valuable for those who have already invested in it and at the same time deter new investments.

Existing solar customers on the LGS-85N TOU Rate Schedule should grandfathered into their existing rate schedules, unless they opt-out, and TEP should offer new solar customers a modified commercial rate designed to be revenue neutral for TEP. The new rate should have a higher, on-peak energy charge and lower demand charges that sends better energy conservation price signals and better aligns with the value solar energy provides.

With regard to the Proposed Lost Fixed Cost Recovery Mechanism (LFCR), TEP is proposing to implement a mechanism intended to keep the utility revenues whole with respect to reductions in sales related to two specific programs – energy efficiency and distributed generation. The LFCR should be modified such that the demand charge-related revenue reduction assumed is based upon actual data taken from customers – not a broad reaching 50% reduction assumption.

Q. How would you describe the proposed changes associated with the rate schedule by TEP?

A. The proposed rates reduce on-peak energy charges and dramatically increase the demand and customer charges. These changes not only remove a significant incentive for customer energy conservation but also dramatically reduce the value of solar generation, which tends to occur during the on-peak hours.[3]

For the LGS-13 rate it is estimated that total kWh charges for summer (May-Sept) are reduced by 44% and for the winter rate (Oct-Apr) by 40%. Regarding the LLP-90N rate, the summer (May-Sept) On-Peak/Shoulder-Peak is reduced by 30.87%, with similarly large decreases in energy charges for the LGS-85N tariff.

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[3] In the APS 2012 IRP document, Attachment D.3, APS lists solar energy as having a capacity value of 50% to 100% depending on the specific technology.

At the same time, the fixed customer charge for those on the LGS-13 rate increases by 142% with the demand charge increasing 103%. Similarly, the LLP-90N customer charge increases by 340% and demand charges increasing anywhere from 10% to 26%, while the LGS-85N customer charge increases by 196% and demand charges increase from 69% to 149%

Q. How does this impact customers with solar energy systems?

A. These rate changes negatively affect customers with solar energy systems. By dropping the per kWh energy offset rate, the economic value of the solar electricity being provided to the customer drops dramatically. In terms of the customers on the LGS-13 rate, the per kWh value of solar they expected from their solar energy systems will drop by around 40%. For many projects, this could completely erase all savings anticipated from the system. For those customers who might have financed their systems, they could now be paying more in financing than they are receiving in savings.

Q. To clarify, these rates would impact past purchasers of solar energy systems as well as future ones?

A. Yes. Customers on those rates purchased solar on the assumption of receiving some specified savings will be severely impacted. Some movements up or down in rates is anticipated, but the severity of decline in the kWh offset is particularly dramatic and unexpected.

For potential future customers, the changes undercut the value proposition of solar energy and instill uncertainty regarding the future financial savings expected over the systems multi-decade operating life.

Q. What type of customer is on these rate plans?

A. The LGS-13 could accommodate high schools, churches, and warehouses while LLP-90n could be for very large commercial operations such as a manufacturing facility or an office/retail complex.

Q. What other concerns do you have about the changes to these rate plans?

A. By changing the rate schedules to the degree proposed, Arizonan's ability to finance distributed generation systems is undermined. Unpredictable or wildly changing rates create more risk for financiers who provide capital to projects for schools and other entities. For example, if a bank made an arrangement with a church to provide upfront capital for a solar energy system in exchange for monthly payments over 20 years, the arrangement is likely to be structured so the monthly debt service payments are less than the savings expected to be provided by the church's solar system. Savings accrue to the church each month that slightly outweigh the financing cost of the solar energy system. However, when this new rate plan goes into effect, the kWh offset of the church's bill will drop by 40%, and the church may find itself "upside down" on the deal. In other words, due to the change in the rate structure, the church is now paying much more to TEP and the bank then they were before the rate change. This increases the probability of default and the risk to the bank.

In a matter of months, potential solar customers will be reluctant to invest in a solar energy system because of the uncertain payback, and, as a result, financiers will escalate pricing to adjust for the increased risk.

Q. How would you resolve this issue you identified?

A. In the near term, I recommend grandfathering in existing solar customers to their original rate plans until the next rate case when TEP will have a chance to design a specific solar rate schedule for the impacted Customer classes described in this testimony. Going forward, I strongly recommend convening a workgroup to determine a solar friendly rate that properly captures the value of solar energy, namely through reduced fixed demand charges and increased energy rates that accurately value the time-of-use generation profile of a typical solar system. Upon design and implementation of such a rate, grandfathered customers would have the option to switch to the new rate or stay on their existing rate.

Q. Please describe the proposed Lost Fixed Cost Recover Mechanism (LFCR).

A. TEP proposed to estimate the lost revenue associated with sales reductions related to energy efficiency and distributed generation programs and develop a rate rider to recover these amounts from all customers.

Q. Do you oppose the LFCR?

A. No. I think a mechanism such as this could be helpful to address TEP's concerns about the volatility of revenue related to fluctuating sales levels. However, there is an assumption within the LFCR with which I do have concern.

Q. Please describe that concern.

A. Essentially, the LFCR attempts to isolate the rate component for each applicable rate class that recovers the utility's fixed costs. The LFCR mechanism implicitly assumes that half (50%) of the demand-based revenues will not be recovered from commercial customers with solar generation, and proposes to recover these revenues through the mechanism. However, this figure is not backed by analysis. One way to more accurately determine any demand charge-related revenue reduction associated with distributed generation or energy efficiency programs is to analyze a representative sampling of such customers over an extended period of time leveraging TEP's advanced metering infrastructure (AMI) network for near real-time interval demand reduction data.

Q. What is your recommendation?

A. TEP should conduct the representative sampling of energy efficiency and distributed generation customers and calculate demand-based revenues that will not be collected by commercial customers with solar generation that will be assumed within the LFCR mechanism.

Q. Does this conclude your Testimony?

A. Yes it does.

Attachment CCH-1

Carrie Cullen Hitt
48 Booth Hill Road
North Scituate, MA 02066
chitt@seia.org

PROFESSIONAL EXPERIENCE

Senior Vice President, State Affairs, Solar Energy Industries Association
January 2013

Vice President, State Affairs, Solar Energy Industries Association
January 2012 – December 2012

- Oversee all state activities for SEIA, including advocacy, relationships with local affiliates and other organizations
- Member of senior management team and a Board level committee
- Manage $3.3m annual budget and four staff
- Presents to the Board and externally on a regular basis.

President, The Solar Alliance
September 2008-December, 2011

- Chief executive and operational officer of a 34 member not-for-profit national trade association.
- Coordinate policies and positions of association in multiple jurisdictions.
- Represent solar PV industry in state and national venues such as NARUC, NCSL,ALEC and NGA.
- Oversee work performed by consultants, lobbyists and regulatory attorneys across the U.S.
- Manage all administrative and business matters of the association, including quarterly board meetings, vendor contracts and a $1.5million budget.

Vice President, Sustainable Energy Solutions, Constellation Energy Resources
March 2007 – September 2008

- Responsible for new product development for retail sustainability products, including renewable energy, greenhouse gas assessment and carbon offsets.
- Develop and implement market strategy, product margin and pricing.
- Manage team of 10 subject and functional experts, as well as the budget for product line.
- Oversee marketing and public relations campaign; operational/processing and sales support.
- Lead company external interface. Including relationships with NGOs and other standard setting parties.
- Direct internal GHG assessment and mitigation program.

Vice President, National Government and Regulatory Affairs, Constellation NewEnergy
January 2004- February 2007

National Director, Government and Regulatory Affairs, Constellation NewEnergy
April 2003 - December 2003 - Baltimore, MD and Boston, MA

- Directed public affairs initiatives for Constellation New Energy, the largest retail electricity company in the U.S. Developed strategy for all company political and regulatory activities in all U.S. and Canadian markets.
- Managed a $7 million budget and staff of 15 located throughout the U.S. and Canada.
- Managed relationships with policymakers, company representatives and industry organizations. Represent the company at industry forums, including government officials and testimony before legislatures and regulatory agencies. Serve as an expert witness.
- Lead public affairs interface and analysis with holding company (Constellation Energy, Fortune 200) and all company affiliates.
- Member of the company's risk, sales commitment and stakeholder management committees. Reported to the President and CEO and served as an officer of the company.

Director, Product Development, Constellation NewEnergy, New England
March 2001 - May 2003 (under AES management) and August 1997-March 1999 - Boston, MA

- Represented the company in the New England and New York.
- Developed regulatory strategy for retail and wholesale operations, including ISO matters.
- Participated in various national industry associations. Managed renewable energy initiatives.
- Established and launched program for small commercial customers.

Director, Regional Business Development, Green Mountain Energy Company
April 1999 – March 2001 - Austin, TX

- Created and implemented business plan for the New England region. Primary focus was residential customers.
- Managed cross-functional project team, negotiated wholesale supply contract, and arranged for substantial investment from state renewable energy fund.
- Represented the company on regional and national regulatory matters.

Assistant Director, Harvard Electricity Policy Group
June 1995 – July 1997 - Cambridge, MA

- Served as administrator for a project focused on competition in the electricity industry in the US and other countries.
- Conducted research and authored reports for project participants, including state and federal policy makers, private and public companies and academics.
- Co-authored several published articles on issues such as wholesale market power.
- Participated in consulting projects for Japan and Thailand. Administered budget and managed participant communication.

Senior Research Analyst, Joint Committee on Energy, Massachusetts Legislature
1991 – 1993

- Analyzed and advised in various aspects of energy policy.
- Reviewed economic and environmental impacts of generation facilities.
- Wrote testimony, authorized reports and opinion pieces.

EDUCATION

M.A. International Economics, the School of Advanced International Studies, Johns Hopkins University, Bologna, Italy & Washington, DC 1995
B.A. Government & History, Clark University, Worcester, Massachusetts 1990

AFFILIATIONS

Member of the Advisory Council to the Interstate Renewable Energy Council
Member of the Board of Directors to the North Carolina Sustainable Energy Association
Formerly on the Board of the Alliance for Clean Energy, New York

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BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP, CHAIRMAN
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	**DOCKET NO. E-01933A-12-0291** **NOTICE OF DIRECT TESTIMONY OF MARK HOLOHAN ON BEHALF OF THE ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION (AriSEIA)**

The Arizona Solar Energy Industries Association (AriSEIA) provides notice of filing of the testimony of Mark Holohan in this docket.

Filed electronically.

Respectfully submitted this 11th day of January 2013.

By [signature]

Arizona Solar Energy Industries Association

Michael L. Neary
Executive Director
111 W. Renee Dr.
Phoenix, AZ 85027

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP, CHAIRMAN
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	**DOCKET NO. E-01933A-12-0291** **DIRECT TESTIMONY OF MARK HOLOHAN ON BEHALF OF THE ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION (AriSEIA)**

Q. Please state your name and business address.

A. My name is Mark Holohan. My business address is 600 E. Gilbert Drive, Tempe, AZ 85281.

Q. For whom are you testifying?

A. I am testifying on behalf of the Arizona Solar Energy Industries Association (AriSEIA).

Q. Please describe the Arizona Solar Energy Industries Association.

A. The Arizona Solar Energy Industries Association is a non-profit trade association composed of companies directly involved in the solar energy industry in Arizona and nationally. AriSEIA member companies include solar energy contractors, manufacturers of solar energy products, system integrators and other companies involved in providing services to the solar industry and consumers. Some Arizona utilities are also members of our association.

AriSEIA and its members have worked for over twenty years to level the playing field for solar energy through the creation of positive public policy, removing barriers, and educating consumers of the many economic development and environmental benefits of solar energy.

Q. What are your professional qualifications?

A. My career includes thirty-five years of experience in power generation, demand side management and solar positions. I worked in the electric utility industry for 17 years as a consultant, manager and engineer. My activities included management of nuclear fuel procurement, construction contract administration, warranty claims, industrial engineering and rate case consulting support. I worked for five years in sales of energy management systems to the large building market in Arizona and was an instructor for the local Certified Energy Manager training program. In the last twelve years I worked in the solar industry including management positions at two solar module manufacturing firms and two electrical contractors. My current position is Solar Division Manager at Wilson Electric, a large commercial electrical contracting firm headquartered in Tempe, Arizona, where I am responsible for development, design and construction activities for commercial solar electric systems. I have been involved in over 150 solar electric projects in several states. I am frequently involved in analyzing customer electric bills and the savings resulting from the addition of distributed solar electric generation systems.

Q. What is your academic background?

A. I have a Bachelor of Science Degree in Nuclear Engineering from the University of Arizona and a Master's Degree in Business Administration from Arizona State University.

Q. **Please describe the proposed changes associated with the rate schedule by TEP?**

A. The proposed changes remove a significant incentive for energy conservation and significantly reduce the value of solar energy that is generated during the on-peak hours. TEP is proposing rates that reduce on-peak energy charges and significantly increase the demand and customer charges.

The fixed customer charge for those on the LGS-13 rate increases by 142% with the demand charge increasing 103%. Similarly, the LLP-90N customer charge increases by 340% and demand charges increasing anywhere from 10% to 26%, while the LGS-85N customer charge increases by 196% and demand charges increase from 69% to 149%

Q. How do these rates affect customers who have installed solar energy systems?

A. Rate changes that lower the cost per kWh reduce the value of the solar energy that is produced. In the case of the LGS-13 rate, this would eliminate any savings that the customer experienced under their previous rate schedule. In addition to affecting customer who have already installed solar, customer who are considering installing solar will no longer do so since the savings potential has been eliminated.

Q. Please explain the difficulty associated with evaluating demand reduction.

A. Demand pricing is a poor pricing signal to customers as most have no idea when their peak demand occurs nor do they take action to reduce demand. It is often not clear if specific energy efficiency measures and solar energy systems will result in a reduction in peak demand. This is partially due to a lack of historical demand data as well as consideration of many variables that affect future demand. Solar energy production is affected by clouds, which adds another uncertainty.

Q. Do you believe current peak demand pricing methods are an appropriate method to reduce peak utility system demand?

A. No. I have observed many cases where customer peak demands are occurring at different times than peak utility system demand. Churches, street lights, and meters for parking lot lighting systems are the first examples that come to mind. I've seen a customer who had a 5:30 a.m. peak due to starting a chilled water system at a school and consistently creating a peak in early morning hours. I've seen wastewater treatment plants that peak in the early morning and late evening, when residential customers tend to take showers. As I previously explained, the difficulties in peak data availability in real time and lack of customer action are additional factors that degrade the value of demand pricing in affecting peak utility system demand.

Q. **Is there a better signal to impact utility system peak demand than customer demand?**

A. Yes. The Time of Use method provides a much more direct signal that customers can respond to since it is so simple, as well as having a clearer link to the relevant time periods of peak utility system demand.

Q. **Please explain the importance of solar energy to ratepayers.**

A. Solar energy is important to ratepayers because it will provide significant and cost effective benefits to all ratepayers, the electrical system and our air quality. Greater use of solar energy saves residential customers and businesses money through reduced energy bills by creating electricity or heating onsite using Arizona's greatest natural resource, the sun. This reduces load growth and the need to build additional power plants which are a major reason for rate increases. Greater use of solar energy also enhances the reliability of the electrical grid, diversifies our energy mix, and reduces the amount of water used to create electricity. Additional benefits include increased jobs and an improved economy. By meeting electricity demand through distributed solar energy, helps relieve system constraints on load pockets, mitigates electricity and fuel price increases for customers and reduces customers vulnerability to fuel price increases.

Q. **Why is it important to consider solar energy in the design of rates this rate case?**

A. It is important to consider changes to the rate structure since rate design can have a significant impact on the expected savings for customers who install solar energy or wish to install solar energy systems in the future. The Commission has adopted a Renewable Energy Standard and Tariff (REST) and the Commission should ensure that TEP can continue to meet that standard by adopting a rate structure that will allow customers to save money with solar energy, not one that negates savings or potential savings through a rate that is not based on an adequate cost per kilowatt hour. There is also the matter of fairness to customers who have already installed solar energy who may see their expected savings devalued through pricing philosophy changes, though their overall rates may be increasing.

Q. **What solution could be available to customers who have installed solar energy systems or are considering installing solar energy systems?**

A. Customers who have installed solar energy systems should be grandfathered into the rate plan that they currently are on or there should be a solar friendly rate for customers, a rate that properly values solar energy. Going forward, I strongly recommend convening a Commission sponsored workgroup to determine a solar friendly rate that properly captures the value of solar energy, namely through reduced fixed demand charges and increased energy rates that accurately value the time-of-use generation profile of a typical solar system. Upon design and implementation of such a rate, grandfathered customers would have the option to switch to the new rate or stay on their existing rate.

Q. Has this type of rate been adopted in any utility service territory?

A. Yes, Southern California Edison, among other, has adopted a rate called the Option R tariff that recognizes a higher value of solar and maintains the savings for customers.

Q. What are the features of this rate for customers?

A. Under this rate there are lower demand charges, and higher On-Peak and Mid-Peak energy charges. Customers on this rate must also own or operate on site renewable energy generation systems.

Q. How does this rate benefit the utility?

A. This rate encourages off-peak electrical usage. A study by SCE of 80 solar customers found that PV installations resulted in a substantial drop in coincident and non-coincident peak demand for those customers. This rate also recognizes solar energy's energy contributions during high system usage periods.

Q. How does this rate benefit the development of solar energy?

A. This rate places a higher and more appropriate value for solar energy and reduces the need for incentives.

Q. What benefits does this rate provide for the ratepayer?

A. This rate is intended to prevent solar customers from subsidizing other customers in this rate class by properly recognizing the benefits solar energy systems provide.

Existing solar customers should be grandfathered into their existing rate schedules and TEP should offer new solar customers a modified commercial rate designed to be revenue neutral for TEP. The new rate should have a higher, on-peak energy charge and lower demand charges that sends better energy conservation price signals and better aligns with the value solar energy provides.

Q. Are there other concerns you have regarding the impact of TEP's proposed rate changes?

A. Yes, the changes to the residential and small commercial rates will also have negative impacts on solar adoption, and more importantly on per capita energy use in TEP service territory. TEP is requesting that both of these rates have disproportionate increases to their fixed charges. While this may make sense from a cost of service point of view, it will have the effect of discouraging customers from minimizing their electricity use. This will cause smaller households and businesses to bear a larger proportion of the effect of the rate increase, and return on investment for energy efficiency measures and renewable energy will be decreased.

Q. What changes would you recommend to the TEP proposed rates for the GS-10 and R-01 rates?

A. I would recommend a proportional increase to the rates. In other words, if TEP is awarded a 10% rate increase, then the fixed charges should increase by 10%, and the energy charges should increase by 10%. I would further recommend that the lowest tier of energy usage (less than 500kwh/billing period) be left at the current rate (no rate increase), and that the middle and higher tiers be increased by slightly more than 10% to compensate for the lack of increase on the lower tier. This would have the effect of providing a fair return to TEP without encouraging higher per capita energy use.

Q. Does this conclude your Testimony?

A. Yes it does.

EXHIBIT
SAHBA-1
ADMITTED

Exhibit SAHBA-1

December 21, 2012
Prepared Direct Testimony

TEP Docket No. E-01933A-12-0291
March 6-8, 2013 ACC Hearings

ORIGINAL

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING OF SOUTHERN ARIZONA HOMEBUILDERS ASSOCIATION**

Southern Arizona Homebuilders Association hereby provides notice of filing of the prepared Direct Testimony of David Godlewski in the above-docketed proceeding.

Dated this 21st day of December 2012.

Respectfully submitted,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.
Attorney for Southern Arizona Homebuilders Association

The original and thirteen (13) copies of the foregoing will be filed this 21st day of December 2012 with:

Docket Control Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

A copy of the same served by e-mail or first class mail this same date to:

All Parties of Record

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BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS *THROUGHOUT* THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-12-0291

Prepared Direct Testimony

Of

David Godlewski

For

Southern Arizona Homebuilders Association

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Prepared Direct Testimony
Of
David Godlewski
For
Southern Arizona Homebuilders Association

Q.1 Please describe your name, business affiliation and business address.

A.1 My name is David Godlewski. I am President of Southern Arizona Homebuilders Association or SAHBA. SAHBA's offices are located at 2840 N. Country Club Road, Tucson, Arizona 85716.

Q.2 Please describe the nature and activities of SAHBA.

A.2 As indicated in its Application for Leave to Intervene in this proceeding, SAHBA is a member trade organization with 340 dues-paying members, which includes Home Builders, Developers, and Associate Members. SAHBA was incorporated in 1952, and its coverage area from the National Association of Home Builders includes Pima, Cochise and Santa Cruz Counties. SAHBA is a 501(C)(6) organization under the United States Internal Revenue Code.

SAHBA represents building industry professionals ranging from builders, developers, land planners, architects, engineers, environmental consultants, trade contractors, banking and mortgage, real estate, and the many supporting disciplines necessary to create, sell, remodel, furnish and maintain new homes and communities throughout southern Arizona. SAHBA provides a venue for its members to share information and to network with other professionals involved in the home building industry. In addition, SAHBA serves as the sponsoring organization of a semi-annual home show allowing members and other merchants to gather and showcase the latest in home improvement and indoor and outdoor living areas.

SAHBA also serves as an advocate for its membership and keeps them apprised of changes in regulatory and governmental matters that will affect their businesses. In that regard, SAHBA actively participated as an advocate on behalf of its membership in proceedings before the Commission in Docket Nos. E-01933A-07-0402 and E-01933A-05-0650, which resulted in the Commission's issuance of Decision No. 72501. That decision reinstated Tucson Electric Power Company's ("TEP") historical line extension tariff provisions, which previously had been "removed" by TEP pursuant to the Commission's Decision No. 70628.

Q.3 Why did SAHBA decide to intervene in this proceeding?

A.3 On July 2, 2012 TEP filed a request with the Commission for an increase in its rates and charges for electric service, which filing occasioned the initiation of this proceeding. As a part of its Application, TEP submitted proposals relating to the subject of Energy Efficiency, which is of interest to SAHBA and its members.

More specifically, during the previously mentioned proceedings conducted in Docket Nos. E-01933A-07-0402 and E-01933A-05-0650, SAHBA indicated its intent to continue to educate its members about and promote the use of Energy Efficiency application in new homes, where feasible. In that regard, SAHBA's members comply with the energy conservation requirements of international and local building codes; and, SAHBA's members have participated in TEP's "beyond code" Energy Efficiency program from time to time. As a consequence, SAHBA concluded that its members must be in a position (i) to continue to inform themselves as to TEP's Energy Efficiency policies and programs, as the same may exist from time-to-time; and, as necessary or appropriate, (ii) to endeavor to influence the same within the context of this proceeding.

It is conceivable that existing TEP Energy Efficiency programs in which SAHBA members currently participate and/or hereafter might participate could be changed or eliminated as a result of this proceeding. Accordingly, SAHBA and its members wanted to be sure that the Commission was aware of our interests and concerns before it reached a final decision on TEP's proposals as the same relate to Energy Efficiency.

Q.4 Has SAHBA identified some potential advantages for SAHBA members in TEP's Energy Efficiency proposals in this proceeding?

A.4 Yes. Based upon our understanding of TEP's filing, including a recent meeting with representatives of TEP, it is SAHBA's understanding that TEP's proposed Energy Efficiency programs would offer advantages for both homebuilders and home buyers, if approved by the Commission.

Q.5 What would be some of the advantages for homebuilders?

A.5 Briefly summarized, the advantages would be as follows. First, improved construction quality as a result of subcontractors having to ensure their work meets associated testing requirements, which also helps reduce subsequent warranty claims. Second, from a marketing standpoint, there can be a competitive advantage for participating homebuilders, which comes from overall energy efficiency and performance, as contrasted with non-program participant homes. Third, financial incentives or rebates help offset increased building costs associated with meeting program standards.

Q.6 What would be some of the advantages for the homebuyer?

A.6 Homes certified by an independent third party are required to satisfy a higher standard for Energy Efficiency than homes built to comply only with the minimum code requirements. The result is lower operating costs for the homeowner resulting from properly sized and higher efficiency HVAC equipment, more efficient window systems and improved indoor air quality.

Q.7 Has SAHBA identified any aspect of TEP's Energy Efficiency proposals in this proceeding which are of concern to SAHBA and its members?

A.7 No, based upon the analysis we have been able to conduct thus far. However, I should note that we are still at an early procedural phase of this proceeding, with the prepared Direct Testimony of the Commission's Staff and other Intervenors and TEP's prepared Rebuttal Testimony yet to be filed, so it is possible that one or more issues of concern might be raised, which SAHBA would respond to in its prepared Surrebuttal Testimony. In addition, it is conceivable that an issue might arise within the context of TEP's Rejoinder Testimony or during the forthcoming evidentiary hearing to which SAHBA might find it necessary to respond, by means of cross-examination and/or post-hearing briefing.

Q.8 Has TEP proposed anything in its July 2, 2012 filing which relates to TEP's line extension provisions which were the subject of the Commission's Decision No. 72501, and SAHBA's participation in Docket Nos. E-01933A-07-0402 and E-1933A-05-0650?

A.8 As of this juncture, TEP does not appear to have proposed any changes to the line extension tariff provisions, which were restored with the Commission's Decision

No. 72501. However, as SAHBA noted in its Application for Leave to Intervene, circumstances can change during the course of a rate case. Accordingly, SAHBA requested intervention in the current proceeding in order to be in a position to preserve the interests of its members with respect to this subject, should a need to do so arise.

Q.9 Does SAHBA have any members who are electric ratepayers of TEP?

A.9 Yes. In addition, SAHBA itself is also one of TEP's ratepayers.

Q.10 Would an increase in TEP's commercial rates and charges for electric service directly impact the cost of doing business for such members and SAHBA?

A.10 Yes.

Q.11 Does SAHBA intend to participate in the settlement discussions which have been scheduled to occur in this proceeding?

A.11 Yes. SAHBA also intends to participate in the evidentiary hearings which will be conducted, with or without a settlement, as and to the extent necessary or appropriate to represent the interests of SAHBA and its members.

Q.12 Does this complete your Direct Testimony?

A.12 Yes, it does.

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EXHIBIT
SAHBA-2

Exhibit SAHBA-2

February 15, 2013
Prepared Direct Testimony
In Support of Settlement Agreement

TEP Docket No. E-01933A-12-0291
March 6-8, 2013 ACC Hearings

ORIGINAL

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING OF SOUTHERN ARIZONA HOMEBUILDERS ASSOCIATION**

Southern Arizona Homebuilders Association hereby provides notice of filing of the prepared Direct Testimony of David Godlewski in support of the Settlement Agreement in the above-docketed proceeding.

Dated this 14th day of February 2013.

Respectfully submitted,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.
Attorney for Southern Arizona Homebuilders Association

The original and thirteen (13) copies of the foregoing will be filed the 15th day of February 2013 with:

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Phoenix, Arizona 85007

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All Parties of Record

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BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-12-0291

Prepared Direct Testimony
Of
David Godlewski
Of
Southern Arizona Homebuilders Association
In Support of the Settlement Agreement

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Prepared Direct Testimony
Of
David Godlewski
of
Southern Arizona Homebuilders Association
In Support of the Settlement Agreement

Q.1 Please describe your name, business affiliation and business address.

A.1 My name is David Godlewski. I am President of the Southern Arizona Homebuilders Association or SAHBA. SAHBA's offices are located at 2840 N. Country Club Road, Tucson, Arizona 85716.

Q.2 Are you the same David Godlewski whose prepared Direct Testimony was filed with the Commission's Docket Control in this proceeding on December 21, 2013?

A.2 Yes, I am.

Q.3 At page 5, lines 14-18 of your prepared Direct Testimony, you indicated that SAHBA intended to participate in the settlement discussions which had previously been scheduled to occur in this proceeding. Did SAHBA in fact participate in those discussions?

A.3 Yes. SAHBA's legal representative was in attendance at all of the settlement discussions which occurred in the Commission's Conference Room in Phoenix; and, he was in attendance during the January 23, 2013 Special Open Meeting when the January 22, 2013 Preliminary Settlement Term Sheet, which resulted from those settlement discussions, was presented to the members of the Commission. In addition, subsequent to that Special Open Meeting, SAHBA and its attorney participated in the negotiations which produced the detailed language of the

Settlement Agreement, which was filed with the Commission's Docket Control on February 4, 2013.

Q.4 Is SAHBA a signatory to the Settlement Agreement?

A.4 Yes, it is.

Q.5 Why does SAHBA support the Settlement Agreement?

A.5 By way of background, and as discussed in my prepared Direct Testimony, SAHBA intervened in this proceeding for two (2) reasons. First, SAHBA's members comply with the base-line energy efficiency requirements of international and local building codes, and SAHBA's members previously have participated in TEP's "beyond code" Energy Efficiency program from time-to-time. Since it was conceivable that existing TEP Energy Efficiency programs in which SAHBA members currently participate and/or hereafter might desire to participate could be changed or eliminated as a result of this proceeding, SAHBA concluded that it was in the interest of its members to intervene and participate in TEP's current rate case. Second, SAHBA wanted to be in a position to advocate, if necessary, for continuation of TEP's historic service extension tariff provisions, which had been reinstated by the Commission in 2011 in Decision No. 72501. The Settlement Agreement addresses each of these objections in a manner acceptable to SAHBA.

Q.6 Does the Settlement Agreement beneficially address these objectives for SAHBA and its members and if so, how?

A.6 Yes, the settlement agreement satisfactorily addresses our objectives. We found the process to be open, transparent and informative. The Agreement is a benefit to our member companies as well as future home buyers. We appreciate the collaborative manner by which TEP worked with SAHBA and our attorney during the process to understand our objectives and work to address them.

Article VII (Energy Efficiency Resource Plan) of the Settlement Agreement specifically addresses the subject of Energy Efficiency. Section 7.1 provides that TEP will implement the Energy Efficiency Resource Plan proposed by the Commission's Staff in its prepared Direct Testimony in this proceeding. In that regard, and of particular importance to SAHBA's members, Section 7.3 provides that beginning March 1, 2013, TEP will resume funding of Energy Efficiency programs previously approved by the Commission.

This is an important feature of the settlement which has been reached, since TEP ceased funding of its various Energy Efficiency programs in the Spring of 2012. Included among those programs was a program relating to Energy Efficiency in connection with the construction of new homes. In that regard, SAHBA and its members are optimistic that TEP will resume funding of this program beginning the first of March, or approximately two (2) weeks from the date of filing of this prepared testimony with the Commission's Docket Control. The restoration of these programs will provide an added incentive to SAHBA's home builder members who desire to construct energy efficient homes that exceed base code requirements. It will also allow builders a marketing advantage they can chose to help sales during this critical time in the recovery of the home building industry. In turn, these homes will conserve energy and create financial savings from lower electric bills for home owners.

Article XVI (Rules and Regulations) of the Settlement Agreement addresses SAHBA's indicated second area of interest. More specifically, Section 16.1

provides as follows:

> "16.1 TEP's revised Rules and Regulations shall be as agreed to between the Company and the Staff. The final version of the Rules and Regulations will be attached to the Company's testimony in support of the [Settlement] Agreement."

Included among those Rules and Regulations attached to TEP's July 2, 2012 prepared Direct Testimony, in which certain language changes were proposed, were Sections 7 and 8. These rules relate to TEP's service extension polices.

During a review of the proposed changes, SAHBA identified one area where some of the new language proposed by TEP created an ambiguity. That ambiguity pertained to the meaning of the word "phases." Accordingly, SAHBA discussed this matter with TEP and suggested some clarifying language, which was acceptable to TEP. The agreed upon language in Paragraph A.4 of Section 8 clarified that the words "number of phases" was a reference to voltage and point of delivery, and was not a reference to construction phases.

In turn, TEP presented SAHBA's suggested clarifying language to the Commission's Staff, which indicated that it no had objection to SAHBA's requested clarification. In that regard, it is SAHBA's understanding that SAHBA's clarifying language will be included in the "final version of the Rules and Regulations" to be attached to TEP's February 15, 2013 testimony in support of the Settlement Agreement pursuant to Section 16.1. Thus, against this background, Article XVI and Section 16.1 are consistent with SAHBA's second intervention objective in this proceeding.

Finally, as noted in SAHBA's July 27, 2012 Application for Leave to Intervene, many of SAHBA's members are customers of TEP. Thus, an increase in TEP's rates and charges for electric service would directly impact the cost of doing business for such SAHBA members. In that regard, it is my understanding that the rate design resulting from the settlement discussions would have the least impact on small businesses. Thus, such a result would be an added benefit for SAHBA members in that rate class.

Q.7 Does SAHBA intend to participate in the evidentiary hearing during which the Settlement Agreement will be formally presented and discussed?

A.7 Yes, as and to the extent appropriate to SAHBA's interests.

Q.8 Does this complete your Direct Testimony in support of the Settlement Agreement?

A.8 Yes, it does.

EXHIBIT
SAHBA-3
ADMITTED

Exhibit SAHBA-3

March 5, 2013
Summary Testimony

TEP Docket No. E-01933A-12-0291
March 6-8, 2013 ACC Hearings

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P. O. Box 1448
Tubac, Arizona 85646

**Summary of Prepared Direct Testimony
Of
David Godlewski
In Support of Settlement Agreement
On Behalf of
Southern Arizona Home Builders
Association**

David Godlewski is President of the Southern Arizona Home Builders Association ("SAHBA"), a member trade organization with 340 dues-paying members. SAHBA's members consists of building industry professionals ranging from builders, developers, land planners, architects, environmental consultants, trade contractors, banking and mortgage, real estate and other supporting disciplines. SAHBA's coverage area from the National Association of Home Builders includes Pima, Cochise and Santa Cruz Counties.

In his February 15, 2013 prepared Direct Testimony in support of the Settlement Agreement, Mr. Godlewski discusses the manner in which the Settlement Agreement satisfactorily addresses two (2) areas of interest to SAHBA's members. First, through the Energy Efficiency Resource Program ("EERP") set forth at Article VII, the Settlement Agreement provides a means for Tucson Electric Power Company ("TEP") to resume funding and implementation of its Energy Efficiency Programs, beginning March 1, 2013. This is of particular interest to SAHBA in connection with TEP's programs relating to the construction of new homes.

Second, as a result of the settlement discussions, TEP is proposing clarifying language to a proposed new subparagraph with its service extension policies, which is also an area of interest to SAHBA and its members. The original proposed language for this subparagraph, as appended to TEP's July 2, 2012 Application and supporting prepared Direct Testimony was ambiguous. As Mr. Godlewski indicates in his testimony, that ambiguity has been removed with appropriate clarifying language.

Finally, many of SAHBA's members are TEP ratepayers, and the cost of electricity is an important cost of doing business. In that regard, as indicated by Mr. Godlewski, it is SAHBA's understanding that the rate design resulting from the settlement discussions would have the least impact on small businesses.

Thus, for the all of these reasons, SAHBA supports the Settlement Agreement.

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EXHIBIT
SAWUA-1
ADMITTED

Exhibit SAWUA-1

January 11, 2013
Prepared Direct Testimony

TEP Docket No. E-01933A-12-0291
March 6-8, 2013 ACC Hearings

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BEFORE THE ARIZONA CORPORATION COMMISSION

AZ CORP COMMISSION
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COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-12-0291 **NOTICE OF FILING OF SOUTHERN ARIZONA WATER USERS ASSOCIATION**

Southern Arizona Water Users Association hereby provides notice of filing of the prepared Direct Testimony of Richard L. Darnall in the above-docketed proceeding.

Dated this 11th day of January 2013.

Respectfully submitted,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.
Attorney for Southern Arizona Water Users Association

The original and thirteen (13) copies of the foregoing will be filed this 11th day of January 2012 with:

Docket Control Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
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All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-12-0291

Prepared Direct Testimony

Of

Richard L. Darnall

For

Southern Arizona Water Users Association

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Prepared Direct Testimony
Of
Richard L. Darnall
For
Southern Arizona Homebuilders Association

INTRODUCTION

Q.1 Please state your name and business address.

A.1 My name is Richard L. Darnall and my business address is 4645 South Lakeshore Drive, Tempe, Arizona, 85282.

Q.2 By whom are you employed?

A.2 I am employed by Utility Resource Strategies Consulting Group, LLC as an Executive Consultant. Utility Strategies Consulting Group ("USCG") provides a wide range of consulting services to electric, gas and water utilities throughout the western United States.

Q.3 Please describe your background and consulting experience.

A.3 I have a Bachelors of Science degree in Accounting from the University of Wyoming and was a practicing Certified Public Accountant for approximately 25 years. I have over 35 years of utility experience. I started out my utility career working for a large investor owned utility located in the Pacific Northwest ending up as Director of Planning and Budgets. I then worked for a large consulting firm located in Phoenix, Arizona for 10 years before starting my own firm. I then started my own firm, Utility Resource Services, Inc., before merging, approximately 8 years ago, with Utility Strategies Consulting Group, LLC. I have testified before numerous state regulatory agencies and the Federal Energy

Regulatory Commission.

Q.4 Who are you representing in this case?

A.4 I am appearing on behalf of the Southern Arizona Water Users Association ("SAWUA"). SAWUA's membership consists of publically- and privately-owned providers of potable and wastewater services, and some who use electricity for agricultural pumping purposes. At present SAWUA's members purchase electricity from Tucson Electric Power Company ("TEP") under rate schedules and tariffs currently designated as PS-43 (Municipal Water Pumping-Firm), PS-45 (Municipal Water Pumping-Intermittent) and GS-31 (Agricultural Pumping-Interruptible).

Q.5 Where are SAWUA's members located, and why was SAWUA formed?

A.5 SAWUA's members are located within the municipal boundaries of the City of Tucson, the Town of Marana, the Town of Oro Valley, the Town of Sahuarita, and various unincorporated areas in Pima County (including the community of Green Valley) and Pinal County.

SAWUA is a nonprofit corporation under the laws of the State of Arizona, and was incorporated in 1999 for the promotion of common business interests of its members, pursuant to Section 501(c)(6) of the Internal Revenue Code. The rates that SAWUA's members pay for electricity is an example of such a common business interest, and thus SAWUA decided to participate as an Intervenor in this proceeding. As indicated in its October 25, 2012 Application for Leave to Intervene, electric rates represent a significant operating expense for SAWUA's members in connection with their respective operations.

Q.6 Who are SAWUA's members?

A.6 SAWUA's current members are as follows: Avra Water Co-Op, BKW Farms, Community Water Company of Green Valley, FICO/Farmers Water Co., Flowing Wells Irrigation District, Green Valley Domestic Water Improvement District, Kai Farms, Town of Marana Municipal Water System, Metro Water District, Oro Valley Water Utility, Pima County Regional Wastewater Reclamation Department, Red Rock Utilities, L.L.C., Sahuarita Water Company, Town of Sahuarita Wastewater and Tucson Water Department. In that regard, the City of Tucson's Water Department and the Town of Sahuarita provide wastewater (and non-potable water) services in the service areas of various members of SAWUA.

Q.7 What is the purpose of your testimony?

A.7 I was asked to review TEP's Schedule G, Allocated Cost of Service and Schedule H, Rate Design and determine if the methodology and analyses used by TEP were fair and reasonable in terms of the rate impact upon the Municipal and Irrigation Pumping customers, which include SAWUA's members. Additionally, I have been asked to review the testimony and exhibits of the ACC Staff, RUCO and other interveners as the same pertain to Schedules G and H and determine if their methodologies and analyses (and resulting rate impact(s) and recommendations) are fair and reasonable with respect to Municipal and Irrigation Pumping customers.

Q.8 Based upon your review and analyses of TEP's Schedules G and H what have you concluded?

A.8 I believe TEP's schedules G and H, as revised, provide a fair allocation of costs to the Municipal and Irrigation Pumping class of customers, and that TEP's proposed rate design will allow TEP to recover an appropriate level of revenues with respect to that class of customers.

Q.9 In your last two answers, you have referred to Municipal and Irrigation customers as a single class, and in an earlier answer, you indicated that SAWUA's members currently purchase electricity from TEP under one or more of Rate Schedules PS-43, PS-45 or GS-31. What is SAWUA's understanding, based on TEP's direct testimony and exhibits, as to what types of customers would be served under TEP's proposed new Rate Schedule GS-43?

A.9 It is SAWUA's understanding that TEP's proposed new Rate Schedule GS-43 will include customers who currently purchase electricity under Rate Schedules PS-43, PS-45 or GS-31. Thus, Rate Schedule GS-43 would be available to the following types of customers (i) public and private potable water and non-potable service providers, (ii) public and private wastewater service providers, and (iii) agricultural pumping. In that regard, electricity purchased under Rate Schedule GS-43 could be used for (i) wells and booster stations used for domestic supply and reclaimed water, (ii) pump stations used for wastewater conveyance and treatment and (iii) agricultural pumping.

Q.10 Have you as yet reviewed the cost allocation and rate design testimony of the ACC Staff, RUCO and other Intervenors?

A.10 No. That testimony is being filed contemporaneously with my cost allocation and rate design testimony on behalf of SAWUA. To the extent any of their cost allocation and/or rate design proposals might adversely impact SAWUA's members, I will address the same in Surrebuttal Testimony on behalf of SAWUA. Similarly, if TEP should propose anything adverse to SAWUA's members in TEP's forthcoming Rebuttal Testimony, I will address that as well in my Surrebuttal Testimony.

Q.11 Does this conclude your prepared direct testimony?

A.11 Yes it does.

EXHIBIT
SAWUA-2
ADMITTED

Exhibit SAWUA-2

February 15, 2013
Prepared Direct Testimony
In Support of Settlement Agreement

TEP Docket No. E-01933A-12-0291
March 6-8, 2013 ACC Hearings

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

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BOB BURNS

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Southern Arizona Water Users Association hereby provides notice of filing of the prepared Direct Testimony of Richard L. Darnall in support of the Settlement Agreement in the above-captioned and above-docketed proceeding.

Dated this 14th day of February 2013.

Respectfully submitted,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.
Attorney for Southern Arizona Water Users Association

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Prepared Direct Testimony
Of
Richard L. Darnall
For
Southern Arizona Water Users Association
In
Support of Settlement Agreement

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Prepared Direct Testimony
Of
Richard L. Darnall
For
Southern Arizona Water Users Association
In Support of Settlement Agreement

INTRODUCTION

Q.1 Please state your name and business address.

A.1 My name is Richard L. Darnall and my business address in 4645 South Lakeshore Drive, Tempe, Arizona, 85282.

Q.2 Are you same Richard L. Darnall whose prepared Direct Testimony in this case was filed on behalf of the Southern Arizona Water Users Association ("SAWUA") on January 11, 2013?

A.2 Yes, I am.

Q.3 You stated in your prepared Direct Testimony that SAWUA's participation in this case would be limited to the review and analysis of allocated cost of service and rate design issues and the presentation of proposals that SAWUA deemed to be appropriate for its members, is that correct?

A.3 Yes.

Q.4 Since the filing of your prepared Direct Testimony, TEP, ACC Staff and the interveners participated in several meetings to discuss a possible settlement of this case. Did you personally participate in the discussions related to cost allocation and rate design?

A.4 Yes.

Q.5 The ACC Staff filed on February 4, 2013 a document called the "Rate Case Settlement Agreement" ("Settlement Agreement") that among other matters addresses the proposed rates and tariffs provisions that are designed to settle this case. Have you had an opportunity to review the rate design portions of the Settlement Agreement and the portions of Attachment "J" to the Settlement Agreement which would affect SAWUA's members?

A.5 Yes, I have.

Q.6 Has SAWUA signed the Settlement Agreement?

A.6 Yes. More specifically, on February 4, 2013, SAWUA's President, Chris E. Ward, executed a signatory page on behalf of SAWUA. However, that signature page was not released for filing with the Settlement Agreement until SAWUA's Board of Directors could meet and receive an explanation as to how the proposed Settlement Agreement and related rate design proposals would address and provide for the interests of SAWUA's members, which I had discussed at pages 3-4 of my prepared Direct Testimony. A meeting of SAWUA's Board of Directors for that specific purpose was held in Tucson, Arizona on February 6, 2013. At that time, SAWUA's Board of Directors voted to support the Settlement Agreement and to ratify Mr. Ward's February 4, 2013 execution of a signature page to be attached to the Settlement Agreement. In that regard, it is my understanding that the signature page executed by Mr. Ward was subsequently transmitted by SAWUA's attorney in this proceeding to the Commission's Docket Control for filing, and that copies of the same were served on all parties of record.

Q.7 Were you in attendance at the February 6, 2013 meeting of SAWUA's Board

of Directors?

A.7 Yes. I participated by speaker phone. During the meeting, SAWUA's attorney of record and I each discussed the proposed new Rate Schedule GS-43, which is the one of interest to SAWUA's members; and, he and I responded to questions from the Board of Directors as they considered whether or not to support and sign the Settlement Agreement.

Q.8 Were you in attendance throughout the Board of Directors meeting, including when they voted to support the Settlement Agreement and ratify SAWUA's President's previous execution of a signature page?

A.8 Yes, I was.

Q.9 Please describe how proposed Rate Schedule GS-43 addresses and provides for the interests of SAWUA's various members.

A.9 As a result of the settlement which was negotiated, TEP's previously proposed new Rate Schedule GS-43 has been modified in several important ways from SAWUA's perspective to create the now proposed Rate Schedule GS-43, which is included in Attachment "J" to the Settlement Agreement.

The first two (2) changes appear in the "Availability" section, where the second and third paragraphs have been added. For ease of understanding, the proposed new "Availability" section is set forth below, and the two paragraphs which have been added appear in italicized font.

"Water Pumping Service (GS-43)

AVAILABILITY

Available for service to the City of Tucson Water Utility and private water Companies where the facilities of

> the Company are of adequate capacity and are adjacent to the premises.
>
> *Available for interruptible service agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.*
>
> *The service points being billed under the PS-43 and GS-31 rate classes as of the effective date of this tariff, but do not meet the above criteria, will be allowed to stay on this rate as long as they meet all other requirements specified in the tariff.*"

Q.10 Why are these two new paragraphs important to SAWUA's members and their respective interests?

A.10 As I discussed in my January 11, 2013 prepared Direct Testimony, SAWUA's members in the aggregate comprise several different types of entities which purchase electricity from TEP for several different water pumping purposes. As may be noted from the "Availability" section of the proposed tariff quoted above, the first paragraph (which also appears in TEP's existing Rate Schedule PS-43) makes the proposed new Rate Schedule GS-43 available to "the City of Tucson Water Utility and private water Companies." But, it is silent as to municipal systems which currently purchase electricity from TEP for water pumping purposes under the Company's existing Rate Schedule PS-43, which will cease to exist if the now proposed new Rate Schedule GS-43 is approved.

However, these existing municipal water pumping entities are provided for in the language of the second new paragraph (or the third physical paragraph) under the "Availability" section quoted above. That is because they satisfy the "service points being billed under the PS-43 and GS-31 rate classes as of the effective date of this tariff, but do not meet the above criteria" language. In that regard, "the above criteria" language there being referred to is the first paragraph in the "Availability" section, which has been carried forward from TEP's existing Rate Schedule PS-43.

The other paragraph addition which is important to SAWUA's members is the first new (or the second physical) paragraph which appears in the "Availability" section of the Rate Schedule GS-43 tariff quoted above. This paragraph provides for those members of SAWUA who purchase electricity from TEP on an interruptible basis for agricultural pumping.

Each of these two new paragraphs under the "Availability" section of the now proposed Rate Schedule GS-43, and the understanding of the role and intended purpose of each which I have described above, was crucial to the decision of SAWUA's Board of Directors to support and sign the Settlement Agreement.

Q.11 You previously mentioned another change to the now proposed language of Rate Schedule GS-43 which also was important to SAWUA's members. What is the nature of that change and where does it appear?

A.11 That change is in the form of a new sentence which has been added to the "Applicability" section of the now proposed Rate Schedule GS-43. That section is set forth below. The new sentence is indicated with italicized font.

> "<u>APPLICABILITY</u>
> Applicable for service to booster stations and wells used for domestic water supply. *For Interruptible service this is applicable to separately metered interruptible agricultural water pumping service for irrigation-purposes of the Customer only.* Not applicable to resale, breakdown, temporary, standby, or auxiliary service."

This language is important to those of SAWUA's members who purchase electricity from TEP on an interruptible basis for their own agricultural pumping purposes. It confirms that they will be able to continue to do so under Rate Schedule GS-43.

Additionally I would point out that the first sentence of the "Availability" section is carried forward from TEP's current Rate Schedule PS-43, and it compliments and confirms the intent of the second new (or third physical) paragraph under the "Applicability" section which I discussed above, as the same pertains to SAWUA's municipal water pumping members.

Q.12 In your original testimony filed on January 11, 2013, you referred to three TEP rate schedules under which SAWUA members were currently purchasing electricity for water pumping purposes: GS-31, PS-43 and PS-45. There are also a number of references in TEP's July 2, 2012 Application to Rate Schedule PS-45. In that regard, on page 47 of Craig A. Jones testimony on behalf of Tucson Electric Power Company, filed on July 2, 2012, the following question and answer appear:

> **"Q. There are three Water Pumping Rates [i.e. GS-31, PS-43 and PS-45]. What changes are being proposed for these rates?**
> **A. The Company is proposing that all water pumping rates be rolled into a single rate schedule. For the water pumping customer that prefers to stay on the interruptible option, the Company is proposing to create a separate PPFAC rate to reflect a discounted fuel cost. This will afford those customers some benefit in the event an interruption is necessary to prevent the Company from having to make a peak period purchase which would otherwise result in higher system fuel costs."**

However, there is no reference to Rate Schedule PS-45 in the Settlement Agreement or Attachment "J" to the Settlement Agreement.

Is it SAWUA's and your understanding that while there are nominally

three rate schedules that are proposed to be "rolled into" the now proposed Rate Schedule GS-43, there are in fact only two currently published tariffs (GS-31 and PS-43) that would be eliminated in the process?

A.12 Yes. It is our understanding that the PS-45 rate schedule refers to the interruptible rate schedule portion within the current Rate Schedule PS-43 tariff. It does not represent a separate and distinct tariff at this time; and, there would not be any occasion to refer to PS-45 hereafter, if the now proposed Rate Schedule GS-43 is approved by the Commission.

Q.13 Is it further SAWUA's and your understanding that those who are currently purchasing electricity under the interruptible rate schedule portion of Rate Schedule PS-43 would be eligible for service under the interruptible service portion of the now proposed Rate Schedule GS-43, and under the new tariff language in the "Availability" section in the now proposed Rate Schedule GS-43, as discussed above?

A.13 Yes, and SAWUA's support for the Settlement Agreement and Rate Schedule GS-43, as set forth in Attachment "J," is also based on this understanding.

Q.13 Does this conclude your Direct Testimony in support of the Settlement Agreement which has been filed in this case?

A.13 Yes, it does.

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EXHIBIT
SAWUA-3
ADMITTED

Exhibit SAWUA-3

March 5, 2013
Summary Testimony

TEP Docket No. E-01933A-12-0291
March 6-8, 2013 ACC Hearings

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P. O. Box 1448
Tubac, Arizona 85646

**Summary of Prepared Direct Testimony
Of
Richard Darnall
In Support of Settlement Agreement
On Behalf of
Southern Arizona Water Users
Association**

Richard Darnall is a Principal in Utility Strategies Consulting Group, a consulting firm based in Tempe, Arizona which provides consulting services to clients on a wide range of matters relating to the electric and water utility industries. In this instance, Mr. Darnall was engaged by the Southern Arizona Water Users Association ("SAWUA") to provide consulting services in the areas of cost allocations and rate design. SAWUA's 16 members include municipal and private water providers, municipal wastewater providers and agricultural pumping entities. In the aggregate, SAWUA's members provide services to several hundred thousand customer connections.

In his February 15, 2013 prepared Direct Testimony in support of the Settlement Agreement, Mr. Darnall describes how Tucson Electric Power Company ("TEP") proposed Rate Schedule GS-43, as appended to TEP's July 2, 2012 Application and supporting prepared Direct Testimony, has been modified through the settlement discussions to satisfactorily address the respective interests and needs of SAWUA's various members. In that regard, Mr. Darnall personally participated in that portion of the settlement discussions related to cost allocation and rate design on behalf of SAWUA. As a result of those modifications, SAWUA supports the Settlement Agreement and TEP's modified proposed Rate Schedule GS-43, as the same pertain to SAWUA and its members.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
SWEEP-1
ADMITTED

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-01933A-12-0291

Direct Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

December 21, 2012

Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-01933A-12-0291

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Please describe the Southwest Energy Efficiency Project (SWEEP).

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting customer benefits, economic prosperity, and environmental protection in the six states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. SWEEP works on state legislation; analysis of energy efficiency opportunities and potential; expansion of state and utility energy efficiency programs as well as the design of these programs; building energy codes and appliance standards; and voluntary partnerships with the private sector to advance energy efficiency. SWEEP collaborates with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. I am the Arizona Representative for SWEEP.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency programs and clean energy resources. I consult for public groups and government agencies; and I have been working in the field for over 25 years. In addition to my responsibilities with SWEEP, I am working or have worked extensively in many states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, New Jersey, Vermont, and Wisconsin. In 1997 I received the Outstanding Achievement Award for the International Energy Program Evaluation Conference. I have testified before the Arizona Corporation Commission in many proceedings.

Q. What is the purpose of your testimony?

A. In my testimony, I will summarize the public interest in increasing electric energy efficiency; discuss the history of Tucson Electric Power's (TEP) energy-saving offerings for customers; explain why energy efficiency, as a fundamental energy resource meeting the real energy needs of customers at lowest cost, must be satisfactorily funded through a stable cost recovery mechanism; comment on

TEP's proposal to amortize energy efficiency program funding as a regulatory asset; recommend modifications to TEP's proposed cost benefit analysis of energy efficiency programs so that it better reflects the true costs and benefits; support full revenue decoupling and oppose TEP's proposed Lost Fixed Cost Recovery (LFCR) mechanism, explaining why it is insufficient for reducing the utility disincentive to pursue energy efficiency; and comment on energy efficiency's role in mitigating large future rate increases for TEP customers.

The Public Interest in Increasing Electric Energy Efficiency

Q. What is the public interest in increasing electric energy efficiency?

A. Electric energy efficiency is in the public interest. Increasing energy efficiency will provide significant and cost-effective benefits for *all* TEP customers, the electric system, the economy, and the environment. Electric energy efficiency is a reliable energy resource that is less expensive than other available energy resources. Consequently, increasing energy efficiency will save consumers and businesses money through lower electric bills and the deferral of unnecessary infrastructure, resulting in lower total costs for customers.

Increasing energy efficiency also reduces load growth; diversifies energy resources; enhances the reliability of the electricity grid; reduces the amount of water used for power generation; reduces air pollution; creates jobs that cannot be outsourced; and improves the economy. In addition, meeting a portion of load growth through increased energy efficiency can help to relieve system constraints in load pockets. By reducing electricity demand, energy efficiency mitigates electricity and fuel price increases and reduces customer vulnerability and exposure to price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages of supply or increased prices for natural gas or other fuels.

Q. What are the estimated costs for energy efficiency savings?

A. Energy efficiency is a reliable energy resource that costs significantly less than other resources for meeting the energy needs of customers in TEP's service territory. For example, in 2011, the cost of energy efficiency programs per lifetime kWh saved was $0.011.[1] Notably, in its 2012 Integrated Resource Plan, TEP identifies energy efficiency as the "lowest cost resource" and uses a levelized cost of energy efficiency of $60/MWh ($0.060/kWh).[2] In comparison, the levelized cost of new generation for other energy resources is substantially more: natural gas combined cycle generation costs between $0.083-$0.115/kWh; coal generation costs between $0.107-$0.200/kWh; and nuclear generation costs $0.136/kWh.[3]

[1] Tucson Electric Power, January-December 2011 Demand Side Management Report, March 1, 2012.
[2] Tucson Electric Power, *2012 Integrated Resource Plan*, April 2, 2012
[3] *Ibid.*

Q. Why should energy efficiency be considered in the context of a rate case proceeding?

A. The Commission, in approving any order that increases rates for customers, should ensure that the least cost resource – energy efficiency – is fully pursued. Consequently in its order on the TEP rate case, the Commission should ensure that TEP is on a pathway to meet the energy savings requirements in the Electric Energy Efficiency Standard ("EEES") by 2016; ensure that there is adequate funding to achieve the EEES energy savings requirements and attain the associated customer and public benefits; and treat energy efficiency as the core energy resource that it is by providing a stable, long-term cost recovery mechanism and funding.

The History of TEP's Energy Efficiency Offerings for Customers

Q. How long has TEP offered energy efficiency opportunities for customers?

A. TEP has offered money-and-energy-saving opportunities for customers since the 1980s.[4] These programs have been recognized as best practices, including TEP's residential new construction program, which has served as a model for other electric utilities. TEP has also been recognized for its innovative offerings, including its Shade Tree program.

Q. At what levels has TEP invested in energy efficiency?

A. From 2009-2011 TEP invested more than $33.6 million in energy efficiency. Over this period, TEP's annual commitment to energy efficiency programs grew from $7.4 million in 2009 to $13.0 million in 2010 and $13.2 million in 2011.

Q. What have TEP's EE programs accomplished?

A. TEP's cost-effective programs have delivered significant economic, energy, and environmental benefits for customers. For example, from 2009-2011, TEP reports that its energy efficiency portfolio delivered:

- Net benefits exceeding $150 million dollars;
- Lifetime savings exceeding 3.5GWh;
- Lifetime savings exceeding 2.2 million therms;
- Lifetime water reductions exceeding 1.5 billion gallons;
- Lifetime SO_x reductions exceeding 3,700 tons; and
- Lifetime NO_x reductions exceeding 4,900 tons.

[4] Tucson Electric Power, Direct Testimony of David G. Hutchens, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, Docket No. E-01933A-11-0055, June 15, 2012.

The Current Status of TEP's Energy Efficiency Programs

Q. What energy efficiency plans did TEP propose before its current Energy Efficiency Resource proposal in the rate case proceeding?

A. In January 2011, TEP filed a 2011-2012 Energy Efficiency Implementation Plan with the Commission. This two-year plan proposed the launch of new and the expansion and continuation of existing customer energy-saving opportunities. The Plan anticipated delivery of cumulative annual energy savings exceeding 300 GWh and net benefits exceeding $130 million.

In this plan TEP proposed several new cost-effective money-and-energy-saving opportunities for customers. These new opportunities were designed to serve more customers (including small business owners; renters; and schools) and provide new ways for customers to save money and energy. These proposed offerings were strongly supported by TEP ratepayers (as evidenced by the hundreds of handwritten and email communications the Commission received in the Implementation Plan docket and the public comments made at open meetings concerning the Plan) and have been successfully implemented in other Arizona electric utility service territories such as the service territories of the Arizona Public Service Company and Salt River Project. In addition, some of the proposed offerings were developed after years of work by TEP ratepayers, including the forty religious institutions that comprise the Pima County Interfaith Council.

TEP's proposal also included a request for expedited review and approval with the goal of launching new and expanding existing customer opportunities by June 2011. This expedited review and Commission approval did not occur.

Q. Has TEP's 2011-2012 EE Implementation Plan, introduced in January 2011, been approved yet?

A. Not yet. TEP's 2011-2012 Plan was considered by the Arizona Corporation Commission at its Open Meeting in January 2012 (a year after it had been introduced and after the 2011 program year had already concluded). At that meeting, and in response to a suggestion from TEP and other stakeholders (including SWEEP), the Commission encouraged interested stakeholders to negotiate a compromise solution to address outstanding issues in TEP's Plan, including TEP's lost fixed cost revenue recovery mechanism (the "Authorized Revenue Recovery True-up" mechanism or AART), which several parties did not support.

Acting on the Commission's request, interested stakeholders including TEP, Commission Staff, the Residential Utility Consumer Office (RUCO), Freeport McMoRan Copper & Gold, Inc., Arizonans for Electric Choice and Competition (AECC), and SWEEP met over several days to contemplate a mutually agreeable compromise. The end product of these conversations was the "Modified Plan," which the Commission considered at its March 2012 utilities Open Meeting. At that Open Meeting, the Commission elected to hold evidentiary hearings on the matter. TEP subsequently updated the Modified Plan to address issues raised by AECC and the lapse in time. This revised plan, the "Updated Modified Plan" – which SWEEP supports alongside TEP, RUCO, AECC, and EnerNOC – was filed on May 2, 2012, and was the subject of an evidentiary hearing in July 2012.

Q. What was the outcome of the evidentiary hearing on the Updated Modified Plan?

A. In August 2012, the Arizona Corporation Commission Hearing Division issued a Recommended Opinion and Order recommending the Updated Modified Plan for approval, specifically noting the strong customer support for TEP's energy efficiency programs.[5] However, the Recommended Opinion and Order has not yet been scheduled for Commission consideration at a Commission Open Meeting.

Q. With TEP's energy efficiency proposals pending, what is the current status of TEP's energy efficiency programs?

A. Following the Commission Open Meeting in March 2012, many of TEP's existing programs serving residential and commercial customers were suspended. In addition, TEP's plans to launch new programs and opportunities to serve more customers were indefinitely delayed. Compared with 2011 levels, existing programs had to be significantly downsized. For example, overall efficiency investment was halved from $11.3 million in 2011 to $5.6 million in 2012, and investment in almost every existing energy efficiency program was slashed dramatically (with the exception of low income weatherization). Energy efficiency program cuts ranged between 12-72%, with the greatest changes to programs serving business and commercial customers.

Q. Why were existing programs suspended and/or cut in 2012?

A. Two factors contributed to the suspension and cuts to existing programs:

1. The Commission approved new energy efficiency programs and expanded program budgets for TEP at several points in the 2010-2011 timeframe, yet the adjustor mechanism to collect the Commission-approved energy efficiency program funding from customers has not been reset to accommodate Commission-authorized program funding levels since June 1, 2010. TEP complied with Commission authorization by implementing the Commission-approved energy efficiency programs and approved budgets, but the ratepayer funding to support the budgets was not collected from ratepayers due to the delay in resetting the adjustor.

[5] Recommended Opinion & Order from the Hearing Division, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, Docket No. E-01933A-11-0055, August 21, 2012.

2. The Updated Modified Plan (and earlier TEP proposals) included a proposal to reset this adjustor mechanism. Because Commission action on the Plan has not occurred, this adjustor mechanism has not been reset to adequately fund Commission-authorized programs and program budgets.

Q. What are SWEEP's concerns about the status of TEP's energy efficiency offerings?

A. SWEEP is extremely concerned about the deep cuts to TEP's energy efficiency programs and suspension of TEP's energy efficiency programs because these programs deliver important and substantial customer, economic, environmental, and utility system benefits. Notably, these programs help customers reduce their energy bills. These program cutbacks have caused significant disruptions in the demand side management marketplace, leading to a loss of local jobs. In addition, proposed new programs and program expansions, which would provide additional cost-effective benefits to customers, have not been implemented. Many of these program cuts also occurred during the summer of 2012, when customer electricity bills were highest, and customers would have benefited from opportunities to save energy and money.

Q. How does TEP's Energy Efficiency Resource proposal in its rate case application relate to the Updated Modified Plan?

A. TEP's Energy Efficiency Resource proposal is separate and distinct from its Updated Modified Plan. However, if approved, TEP's Energy Efficiency Resource proposal would provide stability to customers and the DSM marketplace around TEP's energy efficiency offerings moving forward, ensuring opportunities for customers to save money and energy on their utility bills. As TEP witness Craig Jones explained, the TEP proposal "enhances the current process and establishes a method that should reduce the number and contentious nature of recent EE filings, resulting in a more stable environment for all parties. In this manner, TEP's Energy Efficiency Resource proposal is designed so as not to repeat the challenges encountered with TEP's 2011-2012 Energy Efficiency Plan."[6]

Q. Should the Commission still take action on the Updated Modified Plan before the conclusion of the TEP rate case?

A. Yes, absolutely. Commission approval of the Updated Modified Plan will also ensure delivery of important customer services and benefits in the near-term, before the conclusion of the TEP's rate case. Further delay of energy-saving programs is not in the interest of TEP customers.

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[6] Tucson Electric Power, Direct Testimony of Craig A. Jones, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, Docket No. E-01933A-11-0055, June 15, 2012.

Q. After the rate case concludes, would TEP's proposal provide adequate funding to deliver energy savings into the future?

A. TEP's Energy Efficiency Resource proposal includes total funding for energy efficiency programs of $80 million over three years (August 2013- December 2016), or about $27 million annually. SWEEP commends TEP for contemplating this significant increase to funding energy efficiency programs, however we believe that this level of funding is still insufficient to deliver the level of savings necessary to achieve the EEES by 2016.

Amortizing Energy Efficiency as a Regulatory Asset

Q. What options are generally available to electric utilities for paying the upfront cost of energy efficiency programs?

A. Energy efficiency programs produce long-term energy savings to customers but require some upfront costs for program implementation. Investor owned utilities, like TEP, generally have two ways to pay for these upfront costs. One way is to include the program costs in the company's annual operating expenses; the second option is to amortize program costs, whereby the upfront costs are paid off over time (plus interest), much like a mortgage on a home. This second option would treat energy efficiency as a capital investment, similar to an investment in other energy resources, and would include a Commission-authorized rate of return.

Q. Which of these two options does TEP propose for recovering its energy efficiency program costs as part of its Energy Efficiency Resource proposal?

A. TEP proposes the second option of amortizing energy efficiency program costs as a regulatory asset and recovering those costs over time through its Demand Side Management Surcharge (DSMS) rather than in its base rate.

Q. What are the pros and cons of the two different cost recovery approaches?

A. In general, amortizing energy efficiency as a regulatory asset would help lower the upfront costs and rate impacts of energy efficiency program offerings that are ultimately borne by ratepayers -- just as a mortgage makes it easier to purchase a home. However, this approach will also increase the overall costs of those programs over time. Any investment that is amortized over time will necessarily include a carrying cost (like the interest on a mortgage) required to finance the investment. This increases the overall cost of the investment, but it also eases the upfront cost burden by spreading the costs out over a period of time, thereby reducing initial rate impacts.

Q. Has SWEEP supported similar approaches for treatment of energy efficiency in the past?

A. Yes. SWEEP has supported similar approaches in proceedings before this Commission and before Commissions in other states.

Q. Does SWEEP support TEP's proposal to amortize energy efficiency as a regulatory asset?

A. SWEEP finds TEP's proposal to amortize energy efficiency as a regulatory asset acceptable, especially considering the instability in energy efficiency budget and programs experienced by TEP and its customers over the last two years. We have supported similar approaches in the past and believe it is one we can be supportive of now. However, we do have some concerns about specific aspects of TEP's proposal that could affect the ultimate cost to ratepayers. I will address these aspects in the next part of my testimony.

<u>TEP's Proposal to Amortize Energy Efficiency Program Costs Over Four Years</u>

Q. What factors will affect the cost of amortizing energy efficiency as a regulatory asset?

A. If the Commission authorizes TEP to amortize energy efficiency as a regulatory asset through its DSMS, several factors could affect ratepayer costs and deserve attention by the Commission and other stakeholders. One of these factors is the amortization period for energy efficiency investments.

Q. Why should energy efficiency costs be amortized over time?

A. A fundamental accounting principle for any capital expenditure is to spread the costs of the investment over time so that they are more closely aligned with the stream of benefits produced by that investment. Since energy efficiency programs provide benefits to TEP and its customers over many years, it can make sense to treat energy efficiency investments this way and amortize costs over time. If program costs are not spread out, then the initial costs and rate impacts may appear high to some, even if the investment is prudent over the long term. However, caution must be taken because a longer amortization period will increase the carrying costs required to finance the programs, leading to higher long-term costs to ratepayers.

Q. Does SWEEP support TEP's proposed four-year amortization period for energy efficiency investments?

A. Yes. We believe a four-year amortization period appropriately aligns the costs and benefits to customers of energy efficiency programs, and achieves the appropriate balance. SWEEP would not be supportive of an amortization period longer than four years.

Q. Why does SWEEP not support an amortization period longer than four years?

A. While extending the amortization period may further lower upfront costs and rate impacts to customers, doing so may place a significant burden on both the Commission and TEP's investors.

A longer timeline would result in larger regulatory assets that persist for a longer period of time. Consequently, these regulatory assets would be inherited by future Commissions, potentially restricting the ability of future Commissions to change course as new needs arise. This may put future Commissions in a challenging position, especially if the costs of prior investments remain to be recovered, but the immediate energy savings benefits are not available to all current customers (e.g. if the Commission reduces or eliminates programs). ACC Commissioners have sometimes not been overjoyed about inheriting the costs of decisions made by prior Commissioners.

From a TEP investor perspective, the capital investments in energy efficiency are treated as "regulatory assets" for legal and accounting purposes. Because of this special status, the ability for the company to earn back the original cost of the investment depends on future Commission decisions about rates over the life of the asset. A longer timeline would create significant uncertainty for TEP's investors who may not be willing to finance such a long-lived regulatory asset.

Thus, a balance must be struck between the advantages of longer-term amortization and the additional risks involved. SWEEP believes a four year period strikes that balance.

TEP's Proposed Rate of Return for Energy Efficiency Investments

Q. Are there other major factors that could impact the cost of TEP's energy efficiency programs to customers under TEP's proposal?

A. Yes. Another major factor is the rate of return the Commission authorizes for TEP's energy efficiency resource investments.

Q. What is the "normal" rate of return that a company such as TEP is authorized to earn on its investments?

A. For most of its rate base, a Weighted Average Cost of Capital (WACC) is the "normal" rate of return that the Commission authorizes a company like TEP to earn.

Q. What has TEP proposed for a rate of return on its energy efficiency investments?

A. TEP has proposed that the return on its energy efficiency resource investments be based on the WACC and capital structure the Commission authorizes in its order on the TEP rate case, adjusted to reflect a 200 basis point bonus return in TEP's return on equity.

Q. Is SWEEP comfortable with this proposal?

A. SWEEP is comfortable with a company earning a return on its energy efficiency investments based on the WACC and capital structure the Commission authorizes in its order on the TEP rate case, so long as that return is reasonable and consistent with other Commission rate case decisions.

Q. What is SWEEP's view on TEP's proposed 200 basis point bonus return?

A. Our support for this rate of return is conditional on this bonus return being performance-based, meaning that the level of the bonus return would depend on the performance of TEP's energy efficiency programs.

Q. Why should the bonus return for energy efficiency programs be performance-based?

A. Investments in traditional energy resources only provide value to their shareholders once a plant is in operation. If a company mismanages its capital resources and is unable to deliver an investment, it will be held accountable for these mistakes upon seeking future capital investments. Similarly, energy efficiency programs only provide value if savings levels are actually achieved – an outcome comparable to a plant that is in operation. Thus TEP must be held accountable by the Commission and be encouraged through the bonus return to deliver these savings through a performance-based mechanism in order to justify the enhanced return to its shareholders. This performance-based mechanism should be focused on achieving the savings and benefits for customers, while ensuring that TEP delivers programs cost-efficiently.

<u>TEP's Use of the Societal Cost Test to Evaluate Energy Efficiency Programs</u>

Q. Regardless of how energy efficiency programs are funded, what method does TEP propose for selecting prudent and cost-effective energy efficiency programs and measures?

A. TEP intends to use the Societal Cost Test ("SCT") as the primary means for screening cost-effective energy efficiency investments. TEP further states that it intends only to invest in and implement new EE investments that produce a benefit/cost ratio greater than 1.0, resulting from TEP's analysis, using the Societal Cost Test.

Q. Do Commission rules require use of the SCT to screen energy efficiency investments?

A. Yes, the SCT is the required test for screening and determining the cost-effectiveness of energy efficiency investments under A.A.C. R14-2-2412.B.

Q. What aspects of TEP's proposed SCT does SWEEP not support?

A. TEP should improve their SCT methodology so that it is a true SCT. In particular, TEP's methodology should better align true costs and benefits by using a true social discount rate (as is required by the SCT); by including non-energy and non-market benefits in the SCT; and by improving the valuation of avoided costs. I will address each of these individually starting with the discount rate.

Q. What discount rate has TEP proposed to use in its SCT?

A. TEP has proposed using the Weighted Average Cost of Capital (WACC) as its discount rate for its SCT.

Q. Does SWEEP support TEP's proposal to use its WACC as the discount rate for its SCT?

A. No, using a WACC as the discount rate does not conform to a true SCT.

A true SCT weighs the costs and benefits to all members of society by using a social discount rate that reflects how the public at large values costs and benefits over time. The WACC, however, is a discount rate reflecting the preferences of TEP's lenders and shareholders and not society at large.

If TEP were the sole beneficiary of energy efficiency investments, a WACC would be the appropriate discount rate to use since it reflects how the company's investors value future costs and benefits over time. However, WACC is not relevant for screening energy efficiency investments because TEP is not intended to be the sole beneficiary of any energy efficiency investments implemented. Indeed, the energy efficiency requirements approved by the Commission are intended to provide not only private benefits to TEP, but also public benefits to ratepayers and to society as a whole. Selecting a discount rate that is too high, such as TEP's WACC, will undervalue the benefits energy efficiency provides to the public over time and possibly exclude energy efficiency opportunities that are cost effective under a true SCT. SWEEP believes it is more appropriate to use a social discount rate that reflects the preferences of the larger constituency that benefits from energy efficiency measures, as opposed to the more restrictive use of WACC, which envisions TEP as the sole beneficiary of energy efficiency.

Q. What social discount rate should be applied to TEP's cost benefit analysis for screening energy efficiency investments?

A. In accordance with the October 1, 2010 DSM Collaborative "Memorandum on Arizona Benefit/Cost Analysis of DSM Programs", SWEEP supports the use of a social discount rate based on the yield from U.S. Treasury securities with a cap of 4%. This social discount rate better reflects how the public at large values costs and benefits over time.

Q. Turning now from the discount rate, let's discuss how costs and benefits are quantified in the SCT. In applying the SCT, what is TEP's proposed approach to valuing the benefits of energy efficiency programs?

A. The SCT, as established in Decision No. 71436, allows for the inclusion of societal benefits, including non-market benefits. However, TEP's proposal does not quantify any non-energy or non-market benefits, simply stating that "non-energy benefits will be monetized when supporting research is available." By not including any non-energy or non-market benefits in its analysis, TEP's cost test more closely resembles a different cost test, the Total Resource Cost test, which is not authorized by the Commission under A.A.C. R14-2-2412.

Q. Does SWEEP support the inclusion of non-energy and non-market benefits in TEP's benefit/cost test when supporting research and documentation is available?

A. Yes. A true SCT includes non-energy and non-market benefits. Moreover, supporting research for several of these non-energy and non-market benefits is already available and should enable TEP to quantify at least some of these benefits in its SCT. As an example, SWEEP attaches Exhibit SWEEP-1 showing results from a recent study our organization commissioned to evaluate a variety of benefits that energy efficiency programs provide across the Southwestern U.S. The results include specific non-energy benefits for TEP's service territory such as water savings, which should be included in the SCT.

As SWEEP-1 also shows, job creation is just one of the potential non-market benefits that TEP energy efficiency programs deliver. SWEEP includes Exhibit SWEEP-1 as an example of an analysis it performed quantifying job creation impacts in 2020 of best practice energy efficiency program implementation in the TEP service territory.

Q. What is TEP's approach to valuing the market benefits (i.e., benefits that can be bought or sold) from energy efficiency programs?

A. In brief, TEP estimates market benefits from energy efficiency programs by summing the utility's avoided costs (including energy costs, capacity costs, and environmental costs) that all result from energy savings its programs achieve.

Q. Does SWEEP support this approach to valuing avoided costs?

A. In general yes, however there are some additional benefits that TEP's methodology does not include and deserve attention. For instance, conventional resources carry additional risk to TEP and its customers due to fuel price variability. To the extent that energy efficiency can displace reliance on conventional resources, this provides additional benefits (both market and non-market). Therefore SWEEP supports the inclusion of additional benefits for energy efficiency investments reflecting their ability to hedge against this fuel price risk.

Additionally, TEP should identify any potential future environmental compliance costs (e.g., installing pollution control equipment on coal-fired power plants) that are not already incorporated into its analysis. These compliance costs are distinct from the externality costs already identified in TEP's proposed SCT. We note that a significant driver of TEP's need to increase rates in this rate case stems from the need to install costly environmental compliance measures. As witness Paul J. Bonavia states in his testimony, TEP is anticipating "capital investments of approximately $300 million over the next five years to cover the costs associated with new environmental mandates affecting several power plants." By avoiding future need for conventional energy resources, energy efficiency can also help reduce future environmental compliance costs and these avoided environmental compliance costs should be captured in the SCT.

Q. What is SWEEP's view regarding levelizing avoided cost capacity benefits in the SCT?

A. SWEEP supports levelizing avoided cost capacity benefits in the SCT calculations. SWEEP supports treatment of the avoided cost of generation capacity as annual levelized costs.

Q. We've now discussed the benefits side of the benefit/cost analysis. But what is TEP's approach to valuing energy efficiency program costs?

A. TEP incorporates the following program costs in its benefit/cost analysis: program implementation, marketing, consumer education, measurement and evaluation, training and technical assistance, and planning and administration. Together these comprise the capital cost for each program.

Q. Now that we've established the SCT's basic methodology, how should it be applied to screen prudent and cost-effective energy efficiency investments?

A. The SCT can be used to screen cost-effective energy efficiency investments at both the overall program level and at the individual measure level. The rules established by the Commission speak to both, and SWEEP supports evaluation of cost-effectiveness at the program level. It is important that the SCT evaluations do not restrict the company too severely from pursuing a wide variety of measures and packages of measures that benefit customers, and which can be delivered to customers in a convenient and cost-efficient manner. Accordingly, the Commission should prioritize cost-effectiveness screening at the program level rather than the measure level.

Full Revenue Decoupling to Reduce the Financial Disincentive to Electric Utility Support of Energy Efficiency

Q. Does TEP experience a financial disincentive to its support of energy efficiency when its customers respond and become more energy efficient?

A. Yes. Traditional utility regulation links the utility's financial health to volumetric sales of electricity, resulting in a utility financial disincentive to support energy efficiency and other demand-side resources that reduce sales. Energy savings by TEP customers (which are beneficial for customers, the economy, the utility system, and the environment) result in lower revenues for the Company and the under-recovery of Commission-authorized utility fixed costs. In general, this financial disincentive can reduce utility support and enthusiasm for cost-effective resources such as energy efficiency programs that minimize the long-term costs of providing service. It could also impede potentially crucial utility support for building energy codes and other policies that reduce utility bills for customers and serve societal interests.

Q. Should a decoupling mechanism for TEP be implemented to reduce the financial disincentive and encourage TEP to support additional increases in energy efficiency through programs and other initiatives such as support of building energy codes?

A. Yes. The financial interest of TEP should be better aligned with the interests of its customers by reducing financial disincentives to utility support of energy efficiency, thereby resulting in more energy savings and larger reductions in customer energy bills.

SWEEP supports decoupling mechanisms to address issues related to energy efficiency, i.e., when such mechanisms would be effective in substantially increasing customer energy efficiency and reducing the financial disincentive to electric utility support of increased energy efficiency.

SWEEP is not in favor of decoupling solely or primarily as a mechanism for the utility to recover its fixed costs. Therefore, in SWEEP's view the implementation of decoupling is premised on substantial increases in customer energy efficiency, for which the decoupling mechanism would reduce the financial disincentive to the utility of such increased energy efficiency. Because TEP's energy efficiency proposal will deliver substantial energy efficiency savings for TEP customers, decoupling in this situation is justified.

Q. Does full decoupling effectively reduce Company disincentives to the support of activities that eliminate energy waste, including activities not directly linked to the Company's energy efficiency programs?

A. Yes. Full decoupling effectively reduces Company disincentives to the support of activities that eliminate energy waste. As such, full decoupling is important not only for full utility support of energy efficiency programs but also for activities that reduce sales but are not or may not be directly linked to the Company's portfolio of energy efficiency programs. This could include utility support for building energy codes; appliance standards; energy education and marketing; state and local government energy conservation efforts; and federal energy policies.

Q. Does SWEEP support the "partial decoupling mechanism" (Lost Fixed Cost Recovery or "LFCR") proposed by TEP?

A. No. SWEEP opposes TEP's proposed LFCR mechanism for several reasons. The proposed LFCR mechanism inadequately reduces utility disincentives to energy efficiency, and therefore results in fewer opportunities for customers to reduce their energy bills. Consequently, it does not address the financial disincentive to Company support of building energy codes, appliance efficiency standards, and state initiatives and legislation. It will also likely result in contentious and protracted technical proceedings at the Commission (as has been the experience in lost revenue recovery mechanism proceedings in other states). Finally, the LFCR mechanism represents an automatic rate increase. In contrast, because full revenue decoupling allows for rate adjustments in both a positive and negative direction, decoupling could result in either a credit or a charge on the customer bill.

LFCR does nothing to reduce TEP's financial incentive to encourage customers to use more electricity – and the more customers waste energy, the more TEP revenues and earnings increase. Also, under LFCR, as the Arizona economy recovers and electric demand increases, TEP revenues and earnings would also increase. Specifically, TEP could retain all revenues higher than the revenue levels established by the test year, which would result in higher earnings. TEP would also retain all revenues higher than the revenue levels established by the test year from increased electrification and electric vehicles. In contrast, full decoupling would provide a credit to customers for any revenues higher than authorized revenues (determined as authorized revenue per customer multiplied by the number of customers).

<u>Energy Efficiency's Role in Mitigating Future Capital Expenditures that Cause Rate Increases</u>

Q. How does TEP's proposed increase to base rates compare to previous rate increases and those of its peers?

A. Each rate case has its own unique circumstances so one must use caution when making comparisons. Nevertheless, TEP's proposed rate increase of 15% is significantly higher than its last rate increase of 6% in 2008. It is also much higher than the rate increase recently authorized by the Commission of 3% for Arizona Public Service Company.

Q. In your view, what are the main reasons TEP is requesting such a large rate increase?

A. TEP's request for such a large rate increase is primarily due to the significant capital expenditures the Company made in recent years combined with the rate freeze imposed by the 2008 rate case settlement agreement. Because of this rate freeze, and modest load growth in subsequent years, TEP was unable to recover much of the costs for these new capital expenditures. As stated in the Direct Testimony of Paul Bonavia:

> The Company has invested nearly $1.3 billion in capital from 2007 through 2011 to allow TEP to continue providing safe, reliable, efficient, and environmentally responsible service…
>
> The revenue increase we have requested in this filing was driven higher each year during the rate freeze of the 2008 Settlement Agreement.

SWEEP acknowledges these as credible reasons for TEP's rate increase request. Indeed, new capital expenditures are one of the primary underlying causes for rate increases – particularly capital expenditures followed by low load growth, which limits opportunity for cost recovery.

Q. If TEP's proposal is approved, can we anticipate similar rate increase requests from future capital expenditures?

A. It's impossible to predict what the future holds for TEP and its customers, but we have some clues. For starters, we know that TEP anticipates additional capital expenditures in the near future. Paul Bonavia's direct testimony speaks to this:

> Moreover, we face significant needs in coming years from transmission and distribution system improvements and the looming prospect of costly environmental upgrades at our generating plants.

Meanwhile, TEP recently filed its 2012 Integrated Resource Plan (IRP) with this Commission, which details anticipated future load obligations and resource additions. These include maintaining a large fleet of existing thermal generation resources, which will likely require environmental compliance expenditures. It also includes investment in new natural gas generation capacity over the coming years.

Q. Are you aware of any analysis that reviews the impacts TEP's current proposal will have on future capital needs and compares the impacts to those anticipated in its IRP?

A. No I am not. However, I would encourage Commission Staff and other stakeholders to investigate this question closely since it may be a significant driver of future rate increases.

Q. In your own view, what does the TEP's IRP suggest about its future capital needs?

A. Assuming TEP successfully meets the compliance targets of the Renewable Energy Standard and Electric Energy Efficiency Standard, TEP's load growth will be essentially flat over the coming years. This is illustrated by the forecast Chart 67 of TEP's IRP,[7] which also assumes that economic growth will return to the "normal" levels the Company experienced before the recent recession.

Q. Is it reasonable to assume that TEP load growth will return to levels experienced before the recent recession?

A. SWEEP has no reason to believe this assumption is unreasonable, however any forecast is far from certain. TEP's IRP explores a sensitivity scenario whereby load growth is higher than expected, but not one in which load growth is lower. As such, the Commission should consider the possibility that economic growth will not resume as quickly as TEP forecasts. Importantly, the Commission should also consider that increased energy efficiency savings, including through compliance with the EEES, would reduce load growth to levels lower than the reference case forecast in TEP's IRP. In an attempt to understand the implications of this possibility, SWEEP includes Exhibit SWEEP-2, which shows TEP's load and resource forecasts in accordance with their recently filed IRP, as well as one in which load grows at the rate experienced from 2007-2011.

Q. What conclusions does SWEEP derive from this preliminary analysis?

A. Slower than expected economic growth could lower sales and thus limit TEP's future cost recovery opportunities. Importantly, increased energy efficiency savings, including through compliance with the EEES, would reduce load growth to lower sales levels. This would enable TEP to avoid some of the capital expenditures it currently anticipates such as investments in new natural gas plants. Furthermore, low load growth combined with full energy efficiency compliance may permit TEP to retire some of its existing generation units. This could avoid costly capital expenditures on environmental compliance measures that lead to future rate increases. However, this outcome is only feasible if full compliance with the energy efficiency standard is achieved.

[7] Tucson Electric Power, *2012 Integrated Resource Plan*, April 2, 2012

Conclusion

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT SWEEP-1 – THE $20 BILLION BONANZA: BEST PRACTICE ELECTRIC UTILITY ENERGY EFFICIENCY PROGRAMS AND THEIR BENEFITS FOR THE SOUTHWEST

The table below is excerpted from a presentation given by SWEEP on its recently published report, *The $20 Billion Bonanza: Best Practice Electric Utility Energy Efficiency Programs and Their Benefits for the Southwest.* The full presentation and report can be found at the following website:

http://swenergy.org/programs/utilities/20BBonanza.htm

Estimated Benefits by Utility

	APS	SRP	TEP	UNS El.
Electricity Savings in 2020 (GWh/yr)	6,418	5,966	2,139	401
Net Economic Benefits (billion $)	2.80	2.61	0.93	0.18
Net Increase in Jobs in 2020	3,990	3,710	1,330	250
Water Savings in 2020 (million gallons)	1,575	1,465	525	98

SWEEP

EXHIBIT SWEEP-2 – ANALYSIS OF TEP'S FUTURE LOAD AND RESOURCES ACCORDING TO ITS INTEGRATED RESOURCE PLAN

The chart below illustrates the opportunity for avoiding future capital expenditures (and hence, rate increases) that is afforded by full compliance with the EEES. These data were drawn from information in TEP's 2012 Integrated Resource Plan. The solid black line indicates TEP's forecasted load obligations (including firm wholesale load and planning reserve margins), which the Company anticipates will grow at about 2.2% annually through 2025, *without* energy efficiency impacts. The colored areas underneath this line indicate the planned resources used to fulfill the load obligation. For the last five years, TEP has experienced declining load growth due primarily to the economic recession. The dotted black line represents a future scenario whereby the present trend of declining load growth continues into the future, but in the future resulting from the energy efficiency savings and the EEES. Under such a scenario, the need for resources above this line would be obviated. This could include future capital expenditures on new or existing plants or resources.

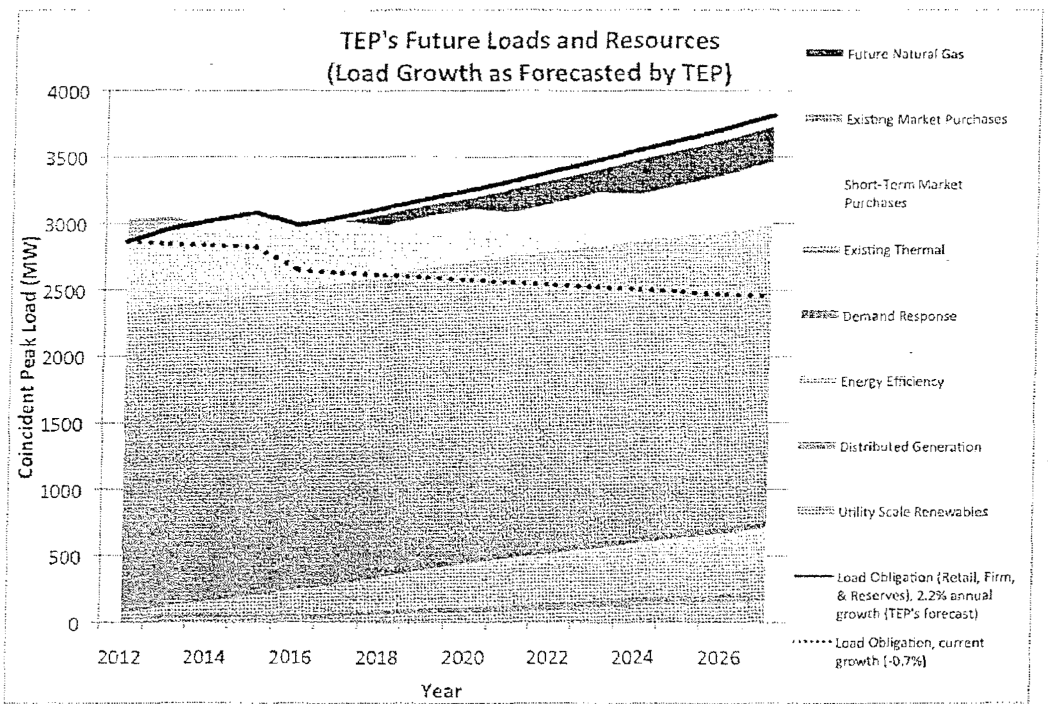

EXHIBIT
SWEEP-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, CHAIRMAN
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-01933A-12-0291

Rate Design Direct Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

January 11, 2013

Rate Design Testimony of Jeff Schlegel, SWEEP
Docket No. E-01933A-12-0291

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Have you filed direct testimony in this docket previously?

A. Yes. I filed direct testimony on behalf of SWEEP on December 21, 2012.

Q. What is the purpose of your rate design direct testimony?

A. In my rate design testimony, I will address three issues:

1. Increasing the basic service charge is not in the interest of customers.
2. Increasing participation in Tucson Electric Power Company's time of use rates.
3. Time of use (TOU) rates for electric vehicles and associated charges should not discourage the adoption of electric vehicles.

Increasing the Basic Service Charge

Q. What is Tucson Electric Power's (TEP's) current basic service charge ("basic charge" or "monthly charge") for residential customers?

A. TEP's current basic service charge is between $7.00 and $8.00 per month.[1]

Q. Does TEP propose to increase this charge in its rate case application?

A. Yes. TEP proposes to increase this charge by $5.00 to $7.00 a month, with resulting basic service charges of $12.00 per month for standard residential customers and $15.00 for residential time of use customers.[2] These are significant increases in monthly charges for customers.

Q. Is increasing the basic service charge, for example, as an alternative to full revenue per customer decoupling or lost revenue recovery mechanisms, in the interest of customers?

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[1] Tucson Electric Power, Direct Testimony of Craig A. Jones, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, Docket No. E-01933A-11-0055, June 15, 2012, at page 32.
[2] Ibid., at page 33.

A. No. SWEEP does not support increasing the basic service charge as a mechanism to recover additional fixed costs. Increasing the basic service charge mutes the price signal to customers by reducing the amount of utility bill cost savings that customers experience when they conserve energy or become more energy efficient. A higher basic service charge reduces the customer incentive to engage in energy efficiency opportunities because customers can affect only a smaller portion of their total utility bills.

SWEEP thinks it is important for customers to be able to maximize savings from energy efficiency, and a higher monthly service charge limits that ability. Monthly basic service charges also have a tendency to fall disproportionately on smaller customers – who can often least afford them. Higher basic service charges are not in the public interest and are not in the interest of customers.

Increasing Participation in and Effectiveness of Time of Use Rates

Q. How many customers participate in TEP's time of use (TOU) rates?

A. TEP reports a total of 10,000 TOU customers at the end of its current test year, with an increase of 2,000 new customers since the company's last rate case.[3] Thus, about 3% of TEP's residential customer base participates in TOU rates.

Q. How does this participation level compare with other Arizona utilities?

A. TEP's TOU participation level is significantly lower than that of the Arizona Public Service Company (APS) and the Salt River Project (SRP). In its 2011 rate case application, APS reported that it had "the highest penetration of TOU in the United States with over 50% of [their] customers on one of [their] TOU rates."[4] Likewise, SRP reported more than 230,000 customers participating in its TOU and EZ-3 prices plans during its 2012 Fiscal Year.[5,6]

Q. Will TEP's proposal to eliminate and consolidate TOU rates drive customer participation?

A. TEP believes that it will. According to TEP Witness Craig Jones, an "unwieldy number" of TOU variations has presented customers with "the daunting task of trudging through a myriad of choices,"[7] and TEP's proposal will help to mitigate this confusion.

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[3] Ibid., at page 23.

[4] Arizona Public Service Company, Direct Testimony of Daniel L. Froetscher, In the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, to approve rate schedules designed to develop such return. , E-01345A-11-0224, June 1, 2011, at page 15.

[5] Salt River Project, 2012 Energy Efficiency Report, http://www.srpnet.com/about/financial/pdfx/EEReport2012_final.pdf.

[6] SRP reported a total of 956,756 electric customers during its 2012 Fiscal Year.

[7] Tucson Electric Power, Direct Testimony of Craig A. Jones, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, Docket No. E-01933A-11-0055, June 15, 2012, at page 41.

SWEEP recommends that TEP also engage in a robust customer education and outreach effort to inform customers of their options and the potential savings benefits of subscribing to TOU options. Similar efforts have been successful for APS and SRP.

Q. Does SWEEP have any concerns about TEP's TOU proposal?

A. Yes. SWEEP is concerned that TEP's proposed summer peak period of 10 a.m. to 9 p.m. is too long and will dissuade customers from participating in TOU rate options. For comparison, peak periods for APS and SRP's residential TOU rates are shown below:

Utility	Rate Plan	Period*	On-Peak Hours
SRP	EZ-3 (E-21)	Year Round	3-6 p.m., Monday through Friday
SRP	EZ-3 Pilot (E25)	Year Round	2-5 p.m., Monday through Friday
SRP	EZ-3 Pilot (E22)	Year Round	4-7 p.m., Monday through Friday
SRP	E26	May - October	1-8 p.m., Monday through Friday
SRP	E26	November - April	5-9 a.m. and 5-9 p.m., Monday through Friday
APS	ET2	Year Round	12-7 p.m., Monday through Friday
APS	ET-SP	June-August	12-3 p.m. (on peak), Monday through Friday; 3-6 p.m. (super peak), Monday through Friday; 6-7 p.m. (on peak), Monday through Friday
APS	ET-SP	May, September, October	12-7 p.m., Monday through Friday
APS	ET-SP	November - April	12-7 p.m., Monday through Friday
APS	ECT-2	May-October	12-7 p.m., Monday through Friday
APS	ECT-2	November-April	12-7 p.m., Monday through Friday

*Off Peak holidays not listed

Q. Should TEP modify its TOU rate proposals and the on-peak time periods?

A. Yes. In order to be effective at achieving the primary objective of TOU rates, which is to shift load from high peak periods to shoulder or off-peak periods, TEP needs to find the right balance between the system characteristics and customer interests and preferences. A TOU rate that has too long of an on-peak period will not be effective in customers shifting load to shoulder or off-peak periods. Customers need to see some benefit in the TOU rate and a reasonable opportunity to make it work for them, considering realistic schedules for customers. A TOU rate with a summer peak period of 10 a.m. to 9 p.m. simply is too long to work for many customers, and compares poorly to other TOU rates in Arizona. SWEEP recommends that TEP should shorten the TOU on-peak period by having it cover fewer hours in the evening, and no later than 7:00 p.m.

Time of Use Rates for Electric Vehicles

Q. Does SWEEP have any concerns regarding the new TOU rates to support electric vehicles?

A. Yes. Language in the TEP rate case states that "For a Customer taking service under a TEP Time-of-Use ("TOU") rate schedule, TEP may charge a fee based on the incremental cost of a TOU meter versus a non-TOU meter." Currently, per TEP's website, those customers that choose a TOU rate have a TOU meter installed for no charge. SWEEP is concerned that the TEP proposal in the rate case could add significant additional costs to customers signing up for TOU rates and thus discourage adoption of electric vehicles, and also make this TOU rate less effective as meeting its objective. Additional meter costs should not be incurred by individual customers. Also, additional costs are already incurred by TOU customers through higher peak prices and higher service charges.

SWEEP opposes any rate or measure requiring electric vehicle owners to install and pay for an additional utility meter, which would add a barrier to public acceptance of electric vehicles.

Conclusion

Q. Does this conclude your rate design testimony?

A. Yes.

EXHIBIT

SWEEP-3

ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291

Testimony in Partial Opposition to the Proposed Settlement Agreement of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

February 15, 2013

Testimony in Partial Opposition to the Proposed Settlement Agreement of Jeff Schlegel, SWEEP

Docket No. E-01933A-12-0291

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. Did you submit direct testimony in this proceeding?

A. Yes. I filed direct testimony and direct rate design testimony on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Have there been any changes in your qualifications or representation of SWEEP?

A. No.

Summary of SWEEP's Testimony in Partial Opposition to the Proposed Settlement Agreement

Q. What is the purpose of your testimony?

A. In my testimony on the Settlement Agreement, I will:

- State why SWEEP is in partial opposition to the proposed Settlement Agreement.
- Describe how the Tucson Electric Power Company's 2012 Integrated Resource Plan demonstrates a need for increased energy efficiency resources, and in so doing, address some of the issues raised by Commissioner Pierce in his letter dated February 1, 2013, regarding energy efficiency, Tucson Electric Power Company's (TEP) need for future resources, and the TEP 2012 Integrated Resource Plan.
- Support the energy efficiency provisions in the Settlement Agreement that would restore energy efficiency programs and ensure that TEP customers receive energy efficiency services to reduce their utility bills, consistent with the resource need documented in the TEP 2012 Integrated Resource Plan.
- State SWEEP's continued support for energy efficiency program cost recovery using either capitalization or expensing, and comment on some related issues raised in Commissioner Pierce's letter dated February 1, 2013.
- Summarize how the proposed Settlement Agreement limits the Commission from fully exploring the policy options for addressing utility financial disincentives to energy efficiency, including limiting the Commission's consideration of full revenue decoupling.
- Describe why full revenue decoupling is a superior option for the treatment of utility financial disincentives to energy efficiency compared to the lost fixed cost revenue recovery mechanism proposed in the Settlement Agreement.

- Recommend that the Commission substitute full revenue decoupling in place of the lost fixed cost revenue recovery mechanism proposed in the Settlement Agreement because full revenue decoupling more completely and effectively reduces utility company disincentives for the support of activities that eliminate energy waste and reduce utility bills, while lost fixed cost revenue recovery does not.
- Describe why the Settlement Agreement's proposal to significantly increase the monthly basic service charge is not in the interest of residential customers.

SWEEP's Partial Opposition to the Proposed Settlement Agreement

Q. Did SWEEP participate in the settlement negotiations in this rate case?

A. Yes, SWEEP participated in the settlement negotiations and believes that the settlement process in this rate case was fair, transparent, and inclusive. SWEEP provided input during the settlement negotiations and the input was considered by the other parties.

Q. What is SWEEP's position on the proposed Settlement Agreement?

A. SWEEP is in partial opposition to the proposed Settlement Agreement.

There are some aspects of the Settlement Agreement that SWEEP can support. For instance, SWEEP appreciates that the Settlement Agreement would restore efficiency opportunities that enable customers to reduce their energy bills. As I explained in my direct testimony, energy efficiency programs have strong customer support and are in the public interest because they deliver important and substantial customer, economic, environmental, and utility system benefits.

SWEEP is in partial opposition to Settlement Agreement because of two provisions:

1. The proposed lost fixed cost revenue recovery mechanism, which inadequately reduces utility disincentives to energy efficiency, and therefore results in fewer opportunities for customers to reduce their energy bills.

2. The significant increase in the residential monthly basic service charge. For a vast majority of customers this increase in the basic service charge will be greater than 40%, which is certainly not gradualism. Also, this increase will limit the ability of customers to maximize savings from energy efficiency.

The Need for Energy Efficiency Resources as Established in TEP's 2012 Integrated Resource Plan

Q. Have issues and questions been raised regarding the treatment of energy efficiency in Tucson Electric Power Company's (TEP) rate case and the proposed Settlement Agreement, which relate to TEP's need for resources and the TEP 2012 Resource Plan?

A. Yes. On February 1, 2013, Commissioner Pierce filed a letter in the TEP rate case docket outlining several thoughts related to the treatment of energy efficiency in the TEP rate case and the Preliminary Settlement Term Sheet, upon which the proposed Settlement Agreement is based.

Q. Please summarize some of the issues that were raised in Commissioner Pierce's letter.

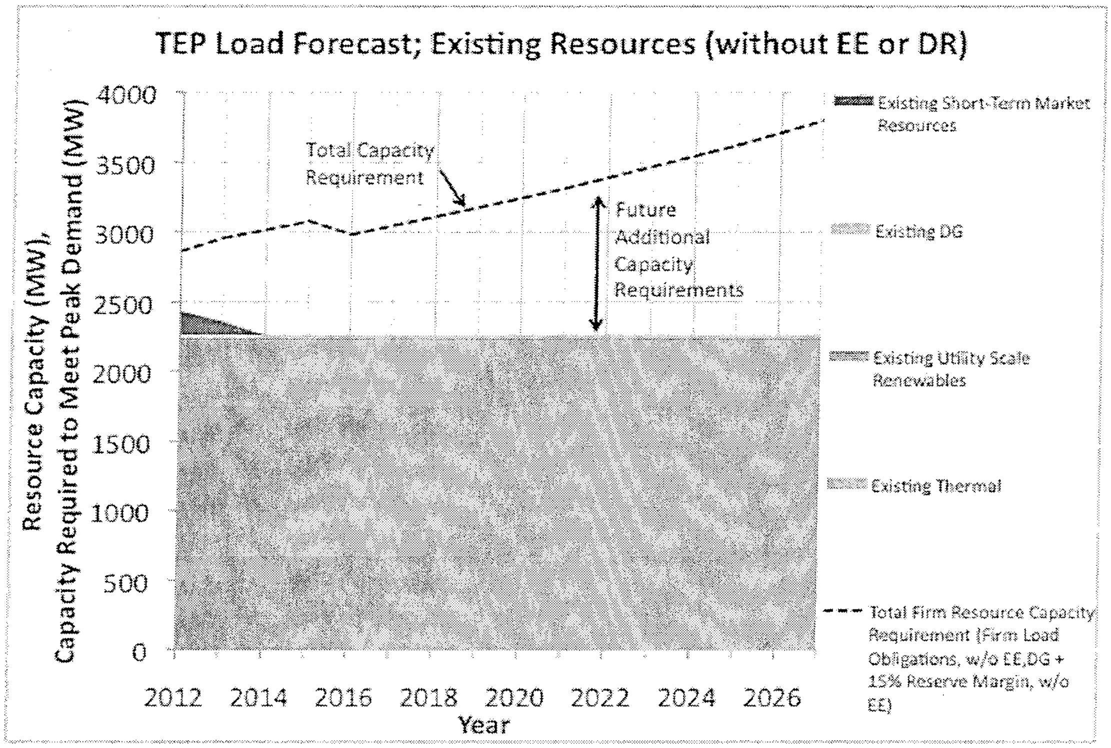
A. Commissioner Pierce asked whether or not the customer resource needs established in TEP's 2012 Integrated Resource Plan (IRP) justified the Company's investment in energy efficiency. In addition, he asked about the proposed Settlement Agreement's Energy Efficiency Resource Plan (" EERP") and whether the EERP circumvents the IRP process.

Q. According to TEP's 2012 IRP, does TEP need additional energy resources to meet its load obligations?

A. Yes. TEP's 2012 IRP clearly shows that TEP has a shortfall in generation capacity over the coming years.

Figure SWEEP-1 shows this capacity shortfall in more detail. The black dotted line represents TEP's total capacity requirement (its firm load obligations plus a 15% planning reserve margin), based on the load forecast in TEP's 2012 IRP. The colored regions below the black dotted line show the capacity contributions of TEP's existing generation resources. The gap between the black dotted line and the capacity contributions of TEP's existing generation resources represents the additional capacity that TEP will need in order to fulfill its load obligations and meet customer needs.

Figure SWEEP-1: TEP's 2012 IRP Demonstrates a Capacity Shortfall Over the Coming Years



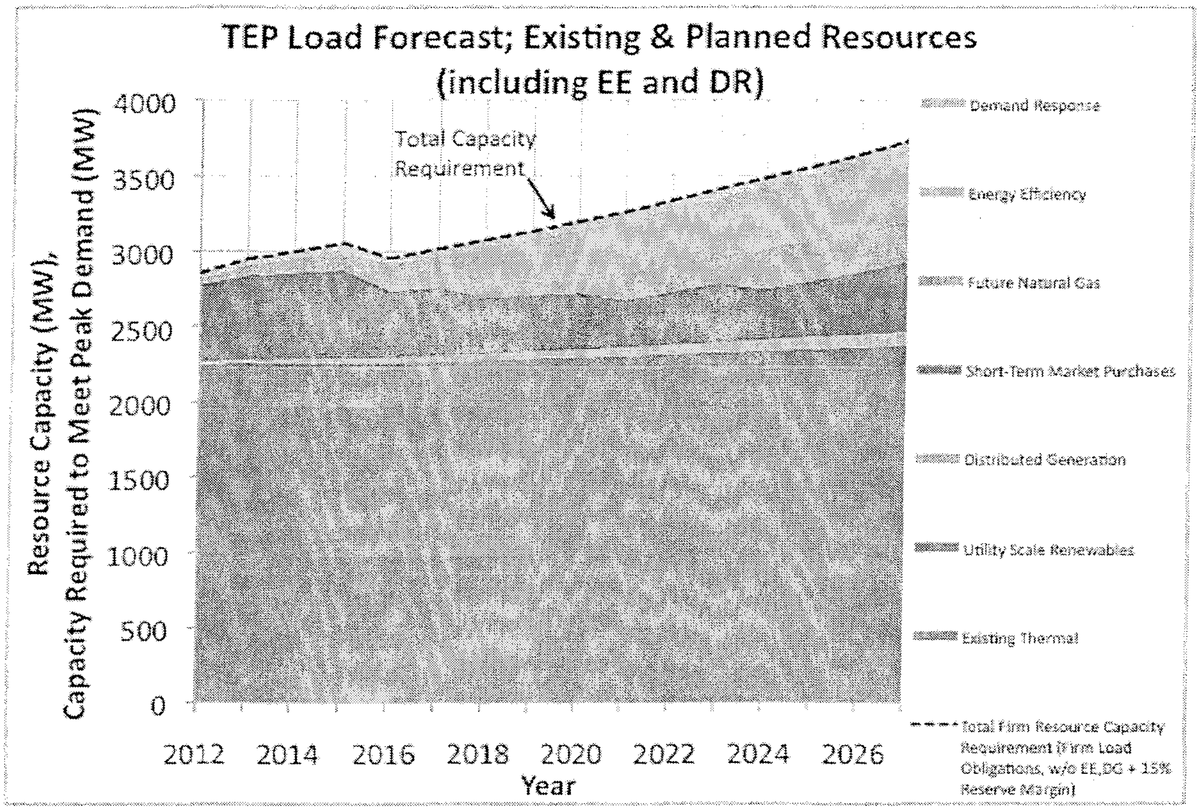
Data Sources: TEP 2012 IRP Table 4, Table 5, Table 14, and Chart 16.

Q. According to its 2012 IRP, how does TEP plan to meet this capacity shortfall?

A. Because of this capacity shortfall, TEP will need to invest in additional energy resources and/or make additional energy purchases in order to fulfill its load obligations and meet customer needs.

According to its 2012 IRP, TEP plans to meet this capacity shortfall through a mixed portfolio of resource additions that include: 1) Supply-side generation resources; 2) Distributed generation; and 3) Demand-side energy efficiency resources and demand response, collectively called "Demand Side Management" or "DSM". See Figure SWEEP-2.

Figure SWEEP-2: TEP Plans to Meet the Capacity Shortfall Through a Mixed Portfolio of Resources, Including Energy Efficiency

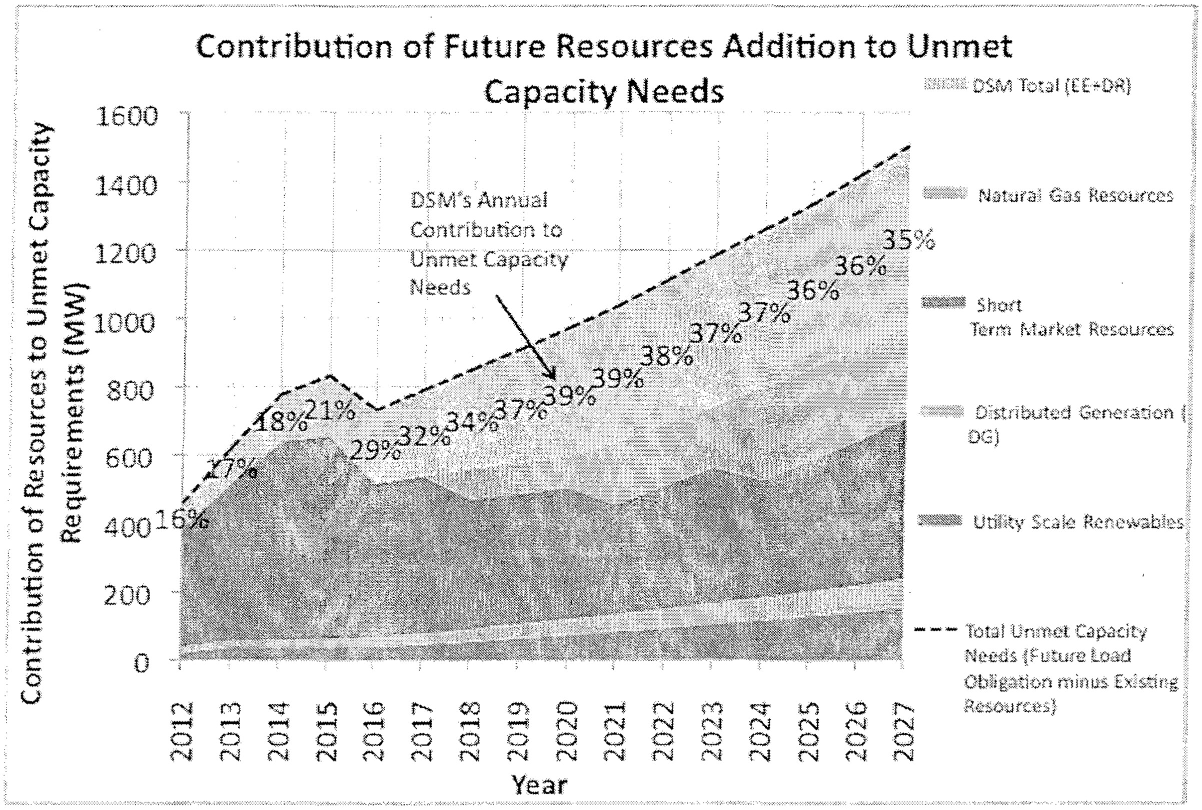


Data Sources: TEP 2012 IRP Table 4 and Table 5.

Q. Specifically, how does Demand Side Management, which includes energy efficiency and demand response resources, enable TEP to fulfill its load obligations and make up for its capacity shortfall, according to the TEP 2012 Resource Plan?

A. Energy efficiency makes a significant contribution toward enabling TEP to fulfill its load obligations and address its capacity shortfall. As shown in Figure 3, during each of the fifteen years in TEP's IRP (2012-2027), Demand Side Management (DSM) programs contribute a major share of TEP's future additional capacity resources to meet capacity needs. Figure SWEEP-3 illustrates the fraction DSM contributes to additional capacity resources to meet the unmet capacity needs in each year over this time horizon. As you can see, DSM contributes over 30% of TEP's future additional capacity resources in most years. In some years, such as 2020, DSM's contribution to TEP's additional capacity resources is as high as 39%.

Figure SWEEP-3: Energy Efficiency Makes a Significant Contribution Toward Enabling TEP to Fulfill its Load Obligations

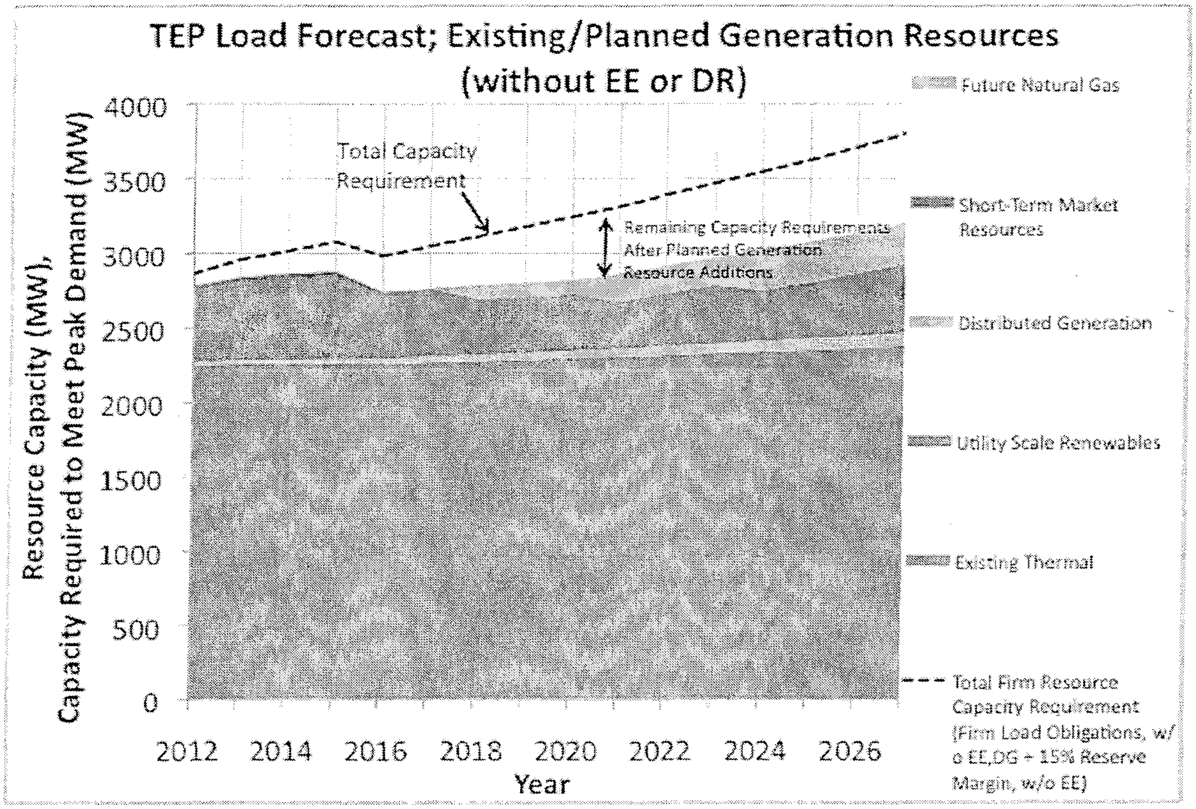


Data Sources: TEP 2012 IRP Table 3, Table 4, and Table 5.

Q. What would happen if TEP did not meet this capacity shortfall with energy efficiency?

A. Without energy efficiency, TEP would have a significant remaining capacity requirement that it would need to meet. This is shown in Figure SWEEP-4. TEP would need to meet this remaining capacity requirement by investing in other energy resources and/or by making additional energy purchases. Unfortunately, these other energy resources are more expensive than energy efficiency and do not compare as favorably from a ratepayer perspective.

Figure SWEEP-4: Without Energy Efficiency Investments, TEP Would Have a Significant Remaining Capacity Requirement



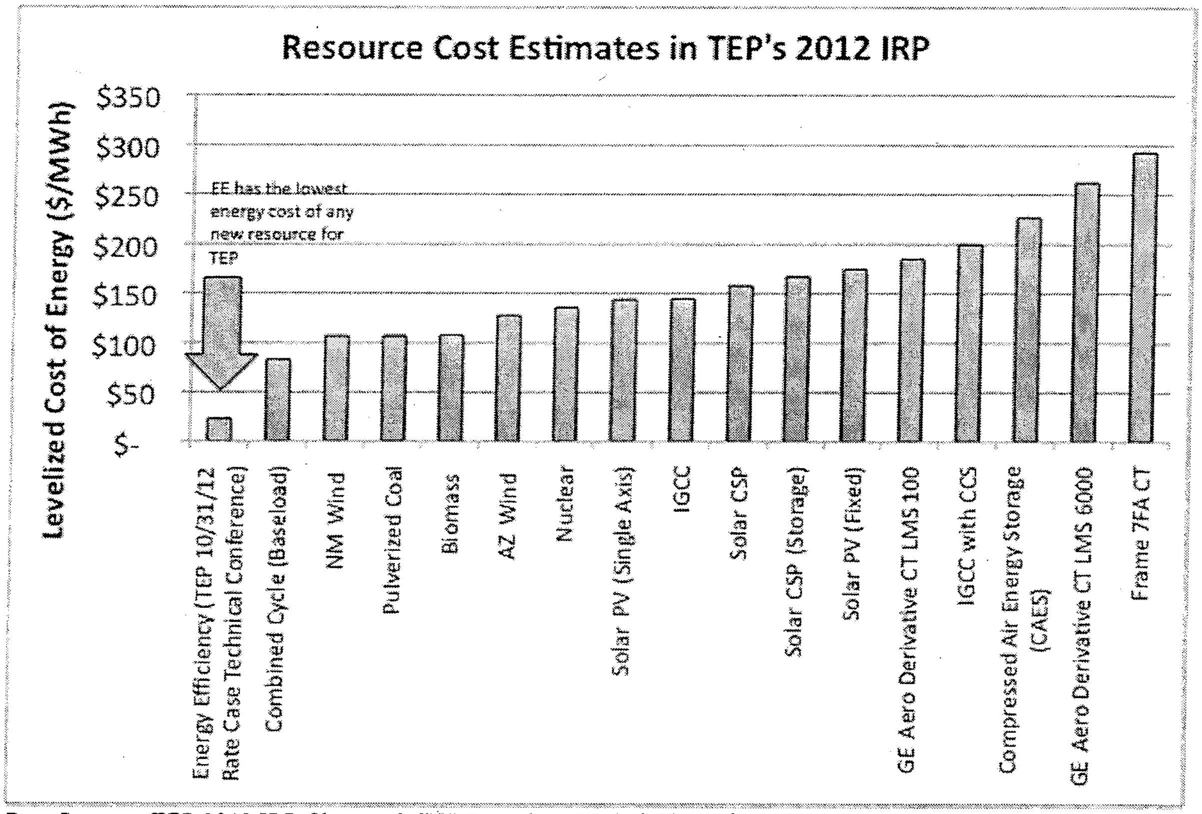
Data Sources: TEP 2012 IRP Table 4 and Table 5.

Q. From a ratepayer perspective, why is energy efficiency more favorable than other energy resources?

A. From a ratepayer perspective, energy efficiency is the best and lowest-cost energy resource TEP can use to meet the needs of its customers. As documented in TEP's 2012 IRP and TEP's rate case technical conferences, cost-effective energy efficiency is the lowest cost, cleanest, least-risky, and most economy-friendly resource. As shown in Figure SWEEP-5, investing in other resources would be more costly for ratepayers. Indeed, TEP estimates its cost for energy efficiency over the 2012-2020 time horizon to be \$23/MWh.[1] Notably, the next most affordable energy resource costs \$83/MWh, which is significantly (more than 3.5 times) more expensive than energy efficiency.

[1] See TEP's October 31, 2012 Rate Case Technical Conference presentation on its Energy Efficiency Resource Plan, which corrected the cost of energy efficiency in TEP's 2012 IRP.

Figure SWEEP-5: Energy Efficiency is the Least Expensive Energy Resource Available to Meet Customer Needs

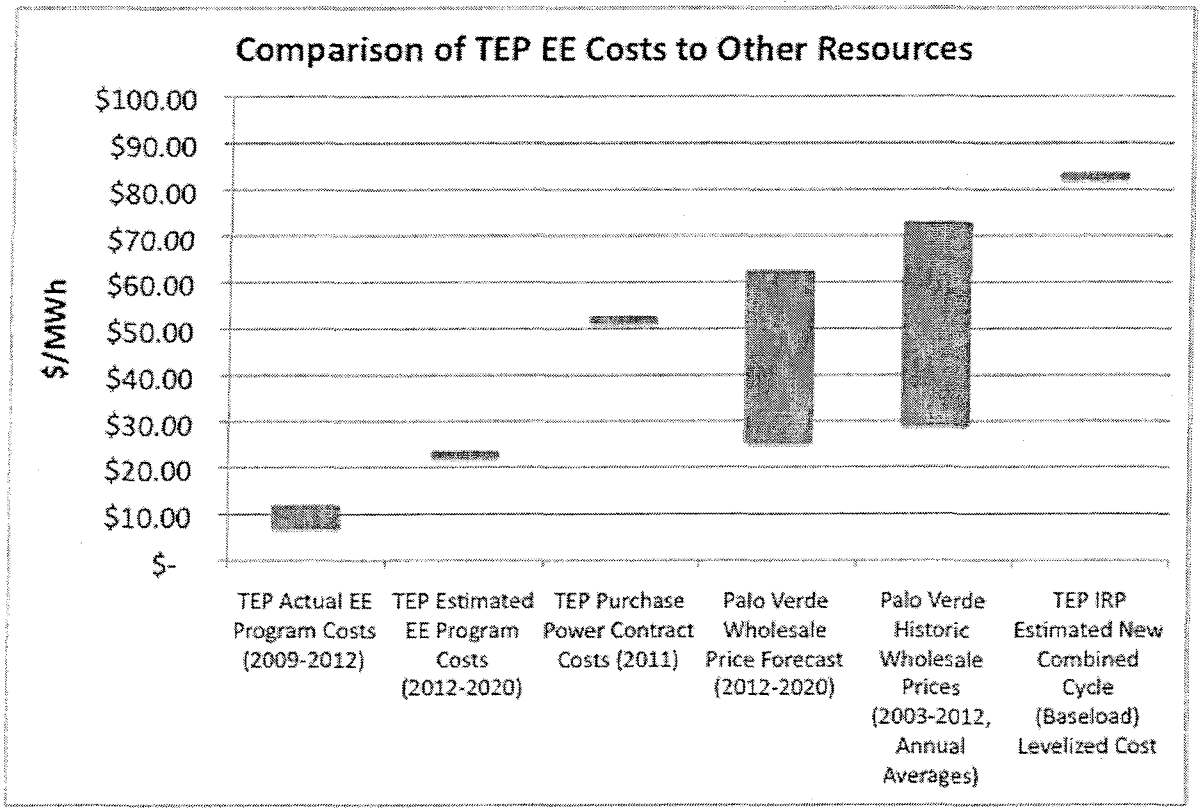


Data Sources: TEP 2012 IRP Chapter 6; TEP Rate Case Technical Conference, EERP, 10/31/2012.

Q. Does energy efficiency also compare favorably to power purchases?

A. Yes. According to TEP's 2012 IRP and information provided in TEP's rate case technical conferences, new and implemented cost effective energy efficiency costs less than merchant power purchases both in recent years and in forecasts over the next decade. See Figure SWEEP-6.

Figure SWEEP-6: New and Implemented Energy Efficiency Costs Less than New and Forecasted Power Purchases Over the Next Decade



Data Sources: TEP Rate Case Technical Conference, EERP, 10/31/2012; TEP DSM Program Progress Reports 2009-2012; TEP 2012 IRP filing for Historical Year 2011, Item B.1.i; TEP 2012 IRP, Chart 62 and page 96; and U.S. Energy Information Administration Wholesale Market Data.

Q. How does the level of energy efficiency proposed in the Settlement Agreement compare to the resource need and level of energy efficiency documented in the TEP 2012 IRP?

A. The level of energy efficiency proposed in the Settlement Agreement is lower than the level of energy efficiency documented in the TEP 2012 IRP.

Q. In your opinion does the TEP EERP and the level of energy efficiency proposed in the Settlement Agreement circumvent the IRP process?

A. No. The data from the TEP 2012 IRP, which I have presented in summary above, clearly demonstrate that there is no "short-circuit in the IRP process." The need to invest in energy efficiency is completely justified based on TEP's actual customer needs as established in TEP's 2012 IRP – which is precisely what should happen, as Commissioner Pierce indicated in his letter.

If anything, TEP should be planning to achieve more energy efficiency than has been proposed in the Settlement Agreement based on the resource needs identified in the TEP IRP.

If TEP under-invests in the energy efficiency documented in the 2012 IRP, and then has to add other resources to substitute for the energy efficiency resources identified in the TEP IRP, the total costs for TEP customers will be significantly higher.

Energy Efficiency Cost Recovery and the EERP

Q. What cost-recovery options are generally available to electric utilities for investing in energy efficiency resources and paying for a portion of the upfront cost of energy efficiency programs?[2]

A. As I discussed in my direct testimony, energy efficiency programs produce long-term energy savings to customers but require some upfront costs for program implementation. Investor owned utilities, like TEP, generally have two ways to pay for these upfront costs. One way is to include the program costs in the company's annual operating expenses; the second option is to amortize program costs, whereby the upfront costs are paid off over time (plus interest), much like a mortgage on a home. This second option would treat energy efficiency as an amortized investment, conceptually similar to an investment in other energy resources, and would include a Commission-authorized rate of return or a mechanism to recover the carrying costs.

As noted in my direct testimony, in concept SWEEP can support either cost recovery mechanism.

Q. Which of these two cost-recovery options does the Settlement Agreement propose for recovering energy efficiency program costs as part of its Energy Efficiency Resource Plan (EERP) proposal?

A. The Settlement Agreement proposes the second option of amortizing energy efficiency program costs as a regulatory asset and recovering those costs over five years through TEP's Demand Side Management Surcharge (DSMS) rather than in its base rate. This amortization proposal for the EERP is not ratebasing and is not identical to how traditional generation resources are treated. Instead, the EERP would amortize and recover the energy efficiency programs costs over a five-year period using a regulatory asset.

Q. Why is the cost recovery for energy efficiency programs different than the treatment of a traditional generation investment?

A. There are two main fundamental differences regarding energy efficiency when compared to other resources. First, the utility does not own the energy efficiency assets; they are owned by customers (and therefore there is not a return to the utility on a utility-owned or investor-owned capital investment). Second, there needs to be timely (generally annual) recovery of utility program costs, because the utility perceives there may be some regulatory risk associated with program cost recovery, yet the utility does not have the business opportunity to earn a return on the utility's investment in an asset that the utility owns. Timely and

[2] Participating customers who install energy efficiency pay for a portion of the costs.

transparent cost recovery helps to ensure that the utility funds energy efficiency to benefit its customers, with less utility bias against energy efficiency resources.

Q. Does treatment of energy efficiency cost recovery through amortization lead to a big financial incentive for the Company to invest in energy efficiency?

A. No. TEP under the EERP does not have a large or significant financial incentive to invest more in energy efficiency, and TEP would not be receiving any financial windfall for funding energy efficiency. Essentially, TEP would be recovering the carrying costs of the regulatory asset, and nothing more.

In fact, given the structure of the EERP per the Settlement Agreement, TEP is facing significant risks regarding energy efficiency program cost recovery, yet TEP does not have an opportunity, beyond recovering the carrying costs, for a financial incentive or increased earnings.

Addressing Utility Financial Disincentives to Energy Efficiency and Preserving the Commission's Ability to Consider Options and Decide Energy Policy

Q. How does the proposed Settlement Agreement offer to address utility financial disincentives to energy efficiency?

A. The Settlement Agreement proposes to implement a lost fixed cost revenue (LFCR) recovery mechanism. This mechanism would recover a portion of the distribution and transmission costs associated with the pursuit of energy efficiency and distributed generation by residential, commercial, and industrial customers. The Settlement Agreement would also allow residential customers to "opt out" of this LFCR mechanism by accepting higher fixed charges through an increased basic service charge.

Q. Does the proposed Settlement Agreement limit the Commission from fully considering the policy options for addressing utility financial disincentives to energy efficiency?

A. Yes. By offering only one option for addressing utility financial disincentives to energy efficiency (i.e., the LFCR mechanism), the proposed Settlement Agreement limits the Commission from fully exploring and vetting the various policy options it could consider, including full revenue decoupling. Indeed, in any adoption of the full Settlement as filed, the Commission would not be able to consider full revenue decoupling at all. Instead, it would have to consider this option *entirely outside* of the Agreement. Accordingly, the proposed Settlement limits the Commission's ability to direct energy policy related to the treatment of utility financial disincentives to energy efficiency.

Q. Why is full revenue decoupling a policy option worthy of Commission consideration?

A. As I testified in my direct testimony, the financial interest of TEP should be better aligned with the interests of its customers by reducing financial disincentives to utility support of energy efficiency, thereby resulting in more energy savings, total lower costs for customers, and larger customer energy bill reductions.

Full revenue decoupling completely and effectively reduces utility company disincentives for the support of activities that eliminate energy waste. As such, full revenue decoupling is important not only for full, enthusiastic utility support of energy efficiency programs but also for activities that reduce sales but are not or may not be directly linked to the Company's portfolio of energy efficiency programs. This could include utility support for building energy codes; appliance standards; energy education and marketing; state and local government energy conservation efforts; and federal energy policies.

Q. Why is full revenue decoupling a superior option for the treatment of utility financial disincentives to energy efficiency than the proposed LFCR mechanism?

The proposed LFCR mechanism inadequately reduces utility disincentives to energy efficiency, and therefore results in fewer opportunities for customers to reduce their energy bills. Consequently, it discourages TEP support of building energy codes, appliance efficiency standards, and state initiatives and legislation. It will also likely result in contentious and protracted technical proceedings at the Commission (as has been the experience in lost revenue recovery mechanism proceedings in other states). Finally, the LFCR mechanism represents an automatic rate increase. In contrast, because full revenue decoupling allows for rate adjustments in both a positive and negative direction, decoupling could result in either a credit or a charge on the customer bill.

LFCR does nothing to reduce TEP's financial incentive to encourage customers to use more electricity – and the more customers waste energy, the more TEP revenues and earnings increase. Also, under LFCR in the Agreement, as the Arizona economy recovers and electric demand increases, TEP revenues and earnings would also increase. Specifically, TEP could retain all revenues higher than the revenue levels established by the Agreement, which would result in higher earnings. TEP would also retain all revenues higher than the revenue levels established by the Agreement from increased electrification and electric vehicles. In contrast, full decoupling would provide a credit to customers for any revenues higher than authorized revenues (determined as authorized revenue per customer multiplied by the number of customers).

Q. Does the proposed residential opt-out rate serve the interest of customers who want to reduce their energy bills?

A. No. The residential opt-out rate requires customers to accept higher fixed charges through an increased basic service charge. As I testified in my rate design direct testimony, and as I testify below, SWEEP does not support increasing the basic service charge as a mechanism to recover additional fixed costs. Increasing the basic service charge mutes the price signal to customers by reducing the amount of utility bill cost savings that customers experience when they conserve energy or increase their energy efficiency.

Q. What action should the Commission take on the Settlement Agreement regarding LFCR and decoupling?

A. The Commission should reject the LFCR mechanism in the Settlement Agreement and require the Company to file a proposal for full revenue decoupling.

Increasing the Basic Service Charge is Not in the Interest of Customers

Q. How does the Settlement Agreement propose to change TEP's current basic service charge for residential customers?

A. In general, the Settlement Agreement proposes to increase TEP's current basic service charge from $7.00-$8.00 per month[3] to $10.00-$11.50 per month.

Q. Is this a significant increase for residential customers?

A. Yes. For a vast majority of customers this increase in the basic service charge will be greater than 40% and sometimes much greater than 40% as compared with current levels. The extent of this increase is certainly not consistent with the important principle of gradualism. And unlike an increase in the energy portion of the utility bill, customers will not be able to take action to reduce or mitigate this increased cost.

Q. What portion of the total rate increase for residential customers is due to the increase in the basic service charge?

A. The Settlement Agreement states that Residential R-01 customers will see an increase in their average annual bill of $34.92. Yet the basic service charge for R-01 customers increases by $3 per month (from $7 to $10 per month). Simple arithmetic would indicate that the increase in the basic service charge is on the order of $36 per year and is therefore a substantial driver of the total rate increase.[4] Notably, this charge is one that customers cannot mitigate or reduce through their actions.

Q. Is increasing the basic service charge in the interest of customers?

A. No, higher basic service charges are not in the public interest and are not in the interest of customers. As I described in my rate design testimony, SWEEP believes it is important for customers to be able to maximize savings from energy efficiency, and a higher monthly service charge limits that ability. Increasing the basic service charge mutes the price signal to customers by reducing the amount of utility bill cost savings that customers experience when they conserve energy or become more energy efficient. A higher basic service charge also reduces the customer incentive to engage in energy efficiency opportunities because customers can affect only a smaller portion of their total utility bills. Monthly basic service

[3] Tucson Electric Power, Direct Testimony of Craig A. Jones, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, Docket No. E-01933A-11-0055, June 15, 2012, at page 32.

[4] Part of the increase in the basic service charge appears to be offset by reductions in other areas of the customer's bill, leading to a total annual increase that is less than $36.

charges also have a tendency to fall disproportionately on smaller customers – who can often least afford them.

Conclusion

Q. Does this conclude your testimony?

A. Yes.